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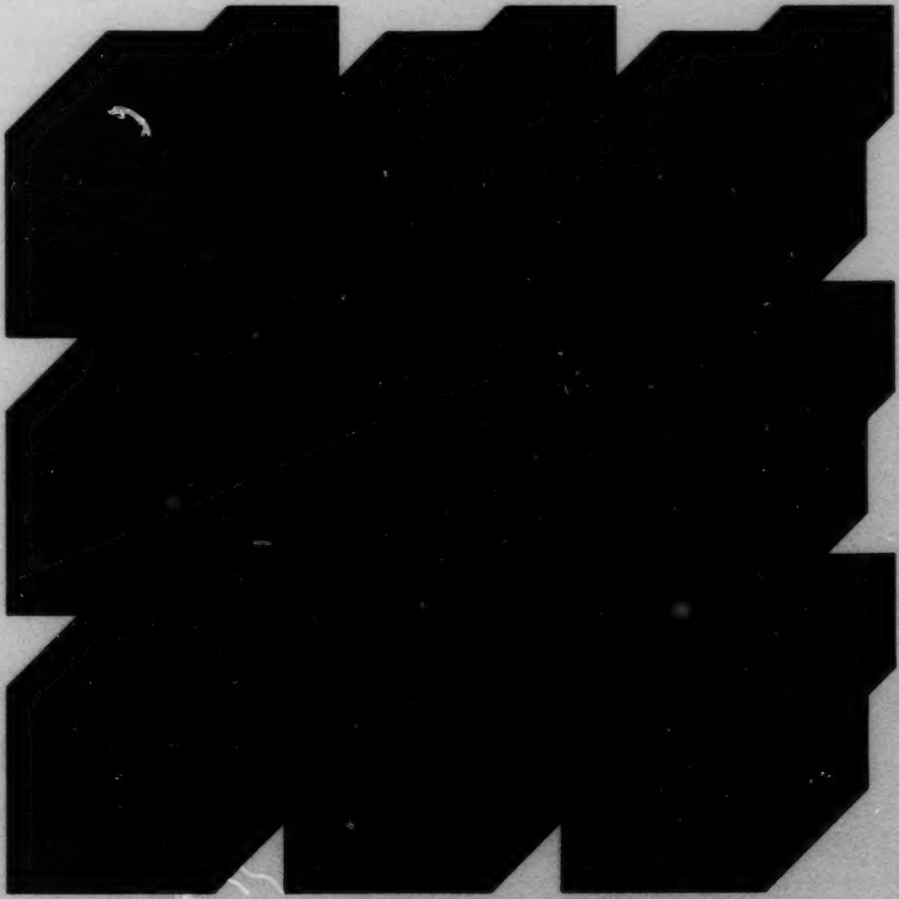

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DISCUSSION PAPER NO. 262

An Assessment of the Competitiveness of Selected Energy Conservation and Alternative Energy Technologies

By Steven G. Diener
Acres Consulting Services Limited
and
Serge Dupont

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Council Secretary
Economic Council of Canada
Post Office Box 527
Ottawa, Ontario
K1P 5V6

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Résumé

- Ce document présente une évaluation de la compétitivité d'une gamme de techniques d'économie de l'énergie et de techniques relatives aux énergies de remplacement, dans le contexte des besoins énergétiques sectoriels et régionaux au Canada. Il expose les hypothèses fondamentales et les méthodes utilisées, et fournit une analyse des conséquences des résultats obtenus, sur le plan des politiques énergétiques.

- Les techniques sur lesquelles portent l'évaluation sont réparties en quatre catégories : 1) les appareils de chauffage pour maisons unifamiliales (les chaudières à gaz à haute efficacité, c'est-à-dire à condensation des gaz, les thermopompes et les appareils de chauffage central au bois); 2) les techniques de production de vapeur et d'électricité dans le secteur industriel (la cogénération, la récupération de la chaleur dégagée, et l'utilisation de la biomasse pour la production de vapeur industrielle); 3) les carburants de remplacement pour le transport (le diesel, le propane, le gaz naturel comprimé (G.N.C.) et le méthanol); et 4) les énergies renouvelables propres à un site (les centrales hydro-électriques à petite échelle, l'énergie géothermique et l'énergie éolienne).

- Nous avons choisi 1995 comme l'année de référence pour l'analyse de la compétitivité des techniques d'économie et de remplacement de l'énergie.

- Nous faisons une distinction entre la rentabilité économique et la rentabilité commerciale d'une technique énergétique. Une technique est jugée economiquement rentable lorsque, du point de vue de l'économie globale, elle permet d'économiser ou de produire de l'énergie à un coût inférieur au coût d'approvisionnement en énergie classique. Sur le plan commercial, une technique est rentable si, compte tenu de la structure existante des prix, des taxes et des subventions relatifs à l'énergie, elle constitue un investissement intéressant pour le secteur privé ou public. Ce document tient compte à la fois de l'analyse économique et commerciale.

- L'analyse économique des techniques repose sur deux ensembles d'hypothèses relatives aux coûts d'option futurs de l'énergie, déterminés, respectivement, à partir de deux scénarios des prix mondiaux futurs du pétrole. Dans le "scénario de référence", nous supposons que le prix mondial du pétrole en 1995 équivaut plus ou moins, en termes réels, au prix en vigueur au milieu de l'année 1983. Dans le "scénario de prix élevé du pétrole", nous supposons que le prix mondial du pétrole s'accroît de 50 % en termes réels entre 1983 et 1995. Dans les deux scénarios, les prix réels du pétrole sont présumés constants à compter de 1995.

- Dans les deux scénarios, nous supposons que les coûts d'option du gaz naturel et de l'électricité en 1995 sont plus élevés que les prix actuels du marché. Les coûts d'option du gaz naturel sont estimés en utilisant une équivalence de l'ordre de 85 % entre les prix du gaz et du pétrole livré à Toronto, au lieu du rapport de 65 % utilisé à l'heure actuelle pour établir les prix du gaz. Les coûts d'option de l'électricité sont fondés sur les coûts d'accroissement de la capacité de production, en supposant des taux d'actualisation réels de 7 % et 10 %; nous supposons que ces coûts sont plus élevés de 15 % dans le scénario de prix élevé du pétrole, en raison non seulement de la hausse du prix du pétrole mais également, de hausses dans les prix du charbon, du gaz et d'autres ressources.

- Dans l'analyse effectuée du point de vue commercial, les prix utilisés sont ceux du marché. Nous utilisons comme hypothèse que les prix du marché au milieu de 1983 demeurent constants, en termes réels, tout au long de la période étudiée.

- Les résultats de l'évaluation des techniques et les retombées qu'ils supposent en matière de politique sont exposés ci-dessous.

Les appareils de chauffage pour maisons unifamiliales

- Dans le scénario de référence, l'analyse économique révèle que la chaudière à gaz à haute efficacité sera, en 1995, le mode de chauffage résidentiel le moins coûteux dans les provinces de l'Est et les Prairies; en Colombie Britannique, la chaudière classique au gaz est plus économique. L'utilisation des thermopompes peut être un moyen efficace de satisfaire à la fois les besoins de chauffage et de climatisation mais le potentiel économique semble se limiter aux régions de l'Ontario et du Québec. Le chauffage central au bois serait le mode le plus avantageux sur le plan des coûts dans les Maritimes et dans les régions rurales canadiennes qui ne peuvent s'approvisionner en gaz naturel.

- Dans le scénario de prix élevé du pétrole, l'utilisation de chaudières à gaz à haute efficacité et des thermopompes est encore plus avantageuse en termes de coûts. Dans les régions rurales, la hausse du prix du pétrole favorise aussi le chauffage au bois.

- L'évaluation économique des nouveaux modes de chauffage indique qu'il y a lieu de douter de la compétitivité du chauffage résidentiel à l'électricité en 1995.

- Du point de vue commercial, l'analyse suggère que les appareils de chauffage qui seront efficaces sur le plan économique en 1995 sont aussi des investissements rentables pour les consommateurs. Toutefois, nous constatons que les propriétaires ou acheteurs de maisons, s'ils fondent leur choix sur une période d'investissement limitée, par exemple de 3 à 5 ans, choisiront probablement des modes de chauffage moins coûteux à l'achat et plus intensifs en énergie.

- Le choix de modes de chauffage plus efficaces, dans le cas des nouvelles habitations, peut être favorisé en proposant aux constructeurs de se conformer à certaines normes de rendement énergétique et en informant les acheteurs des niveaux d'efficacité souhaitables. Il est préférable de laisser le marché déterminer le niveau et le type d'investissement nécessaire pour atteindre les objectifs énergétiques.

- Dans le domaine de la réfection domiciliaire, il semblerait nécessaire de modifier le programme actuel de subventions pour la conversion des chaudières (P.C.R.P.) afin d'inciter les consommateurs à délaisser les rénovations habituelles (par exemple, celles qui se rapportent aux éléments chauffants dans le caisson ou aux chaudières classiques) et à investir plutôt dans des travaux de réfection plus efficaces et plus avantageux sur le plan économique.

Les techniques de production de vapeur et d'électricité dans le secteur industriel

- La cogénération

- Le potentiel technique de la cogénération correspond à 6 % et 8 % respectivement de la capacité et de la production d'électricité au Canada en 1981.

- Selon le scénario de référence, le potentiel énergétique pourrait être réalisé dans une proportion de 85 % à 95 % à un coût moins élevé que celui de la production d'électricité par des moyens classiques en 1995. Dans le scénario de prix élevé du pétrole, le potentiel économique est de 70 % à 90 % du potentiel technique.

- L'évaluation économique de la cogénération dans les industries du bois et du papier laisse à entendre que l'utilisation de la biomasse pour la production d'électricité peut être très avantageuse sur le plan des coûts.

- D'après nos estimations, le potentiel commercial, c'est-à-dire de pénétration du marché, de la cogénération ne représente que la moitié du véritable potentiel économique. À l'heure actuelle, l'offre excédentaire d'électricité au Canada et les faibles tarifs qu'elle entraîne dans le secteur industriel ont pour effet de freiner la mise en application des procédés de cogénération. Il y aurait lieu, à mesure que s'épuise la capacité excédentaire de production d'électricité, de prendre des mesures destinées à stimuler l'adoption du procédé de cogénération, afin que des installations de ce type permettant de produire de l'énergie à faible coût soient mises en place. Le niveau des subventions pourrait décroître avec le temps et pourraient éventuellement être supprimées.

- La récupération de la chaleur dégagée

- Le potentiel technique que représente la récupération de la chaleur dégagée dans les secteurs manufacturier et minier au Canada correspond à environ 10,8 % de l'énergie consommée dans ces deux secteurs d'activité.

- Il ressort de l'évaluation économique que bon nombre des projets fondés sur le principe de la récupération permettraient de recycler l'énergie à un coût inférieur aux coûts d'option du pétrole et du gaz naturel tel qu'estimés dans le scénario de référence. En termes de coûts, ces projets présentent des avantages encore plus grands dans le scénario de prix élevé du pétrole.

- Le potentiel économique du procédé de récupération de la chaleur dégagée pourrait être l'équivalent d'environ 40 % du potentiel technique.

- La plupart des projets de récupération de la chaleur dégagée jugés économiquement rentables peuvent s'avérer viables sur le plan commercial. Reste à savoir si les investisseurs industriels tireront pleinement parti de ces possibilités d'économie de l'énergie. Les gouvernments pourraient mettre au point, à un coût peu élevé, des programmes d'aide financière destinés à réduire les risques perçus par les investisseurs et à stimuler l'adoption des procédés les plus efficaces.

- Les techniques plus avancées de récupération de la chaleur dégagée, telles que l'utilisation inter-usines de l'énergie en cascade seront vraisemblablement moins avantageuses à court et à moyen terme. Toutefois, il y aurait lieu de favoriser le progrès technologique dans ce domaine en vue d'une amélioration à long terme de la productivité et de la compétitivité de l'industrie.

- La biomasse

- L'utilisation de la biomasse (par exemple, les déchets solides municipaux ou les résidus du sciage) serait avantageuse sur le plan tant économique que commercial.

- Dans le scénario de référence, le potentiel économique des usines de production de l'énergie à partir des déchets (surtout des usines de traitement des déchets solides municipaux) pouvant alimenter des industries voisines correspondrait à près de 60 pétajoules par année. Dans le scénario de prix élevé du pétrole, ce potentiel est porté à 68,5 pétajoules par année, ce qui équivaut à environ 7 % du volume total des produits pétroliers et du gaz naturel consommé dans l'industrie canadienne en 1982.

- L'analyse commerciale révèle que, sur la base des prix actuels de l'énergie, l'utilisation des déchets solides municipaux pour produire de la vapeur industrielle peut être rentable tant pour les gouvernements régionaux que pour l'industrie.

- Différents facteurs structurels contribuent à retarder l'exploitation d'usines de récupération d'énergie à partir des déchets solides. Les projets de cette nature nécessitent la collaboration de nombreux participants dont aucun ne semble vouloir jouer le rôle de promoteur principal. Les entrepreneurs industriels, en particulier, hésitent à participer à des projets qui impliquent une dépendance accrue à l'égard d'installations appartenant aux gouvernements.

- L'exécution de projets pilotes pourrait être favorisée par un organisme multipartite spécialisé dans les techniques de récupération d'énergie à partir des déchets solides et dans la planification des projets. Ces projets nécessiteraient sans doute, à court terme, une aide financière directe du gouvernement fédéral ou des provinces. Le niveau d'aide requise devrait décroître avec le temps, à mesure que les résultats des premiers projets pilotes confirment la fiabilité et la rentabilité des usines de récupération.

Les carburants de remplacement pour le transport

- Dans le scénario de référence, l'essence et le diesel s'avèrent, respectivement, les carburants les plus économiques pour les voitures particulières (à faible kilométrage) et les véhicules commerciaux (à kilométrage élevé). Dans le scénario de prix élevé du pétrole, le diesel est le moins coûteux pour les deux types de véhicules.

- L'évaluation économique montre que les prix du propane et du gaz naturel comprimé (G.N.C.) sont moins concurrentiels que ceux de l'essence ou du diesel, et ce dans les deux scénarios de prix du pétrole. Le méthanol est un carburant encore plus coûteux. Toutefois, le méthanol, tel que le G.N.C., semble présenter certains avantages à plus long terme en raison de l'abondance des sources d'approvisionnement.

- À l'heure actuelle, les gouvernements encouragent l'utilisation du propane et du G.N.C. Notre analyse montre que, du point de vue commercial, les programmes d'incitation du gouvernement produisent de bons rendements pour les propriétaires de parcs de véhicules qui investissent dans la conversion à un de ces types de carburants. En revanche, aucune mesure n'est en place pour stimuler la conversion au carburant diesel.

- Nous constatons qu'il faudrait modifier les politiques afin d'établir une stratégie plus efficace pour l'implantation des carburants de remplacement. Les provinces pourraient modifier les politiques de taxation des carburants pour que l'utilisation du diesel devienne plus avantageuse. Les programmes fédéraux de conversion pourraient être réévalués. Les fonds qui sont actuellement réservés à la commercialisation immédiate du propane et du G.N.C. pourraient possiblement être utilisés de façon plus productive dans des programmes de recherche visant à mieux évaluer et à améliorer le potentiel à long terme du méthanol et du G.N.C.

Les énergies renouvelables propres à un site

- Les centrales hydro-électriques à petite échelle

- Il peut être démontré que, dans certains sites, l'exploitation de centrales hydro-électriques à échelle réduite fournissant 2 mégawatts (MW) ou plus à des entreprises industrielles voisines peut être rentable sur le plan économique et commercial.

- Au cours des dernières années, ces projets ont été très peu nombreux, d'une part, à cause des tarifs peu élevés de l'électricité et, d'autre part, en raison de la rareté des promoteurs de tels projets.

- Pour favoriser la diffusion des techniques de production hydro-électrique à petite échelle, les responsabilités en matière d'exploitation des petites centrales devraient être définies à l'intérieur des sociétés hydro-électriques provinciales. Il faudrait également inciter les industries à réaliser de tels projets et à être propriétaires de telles centrales. Au niveau fédéral, il faudrait prolonger les programmes en vigueur prévoyant de l'aide pour les projets de remplacement du pétrole dans les collectivités éloignées.

L'énergie géothermique

- Du point de vue technique, le potentiel de l'énergie géothermique est limité par des considérations géographiques. Le potentiel économique et commercial est limité davantage par les modes d'utilisation possibles et le nombre d'utilisateurs éventuels.

- Nous avons examiné quatre modes d'utilisation : le chauffage des serres, la climatisation et la ventilation des mines, le chauffage des locaux et de l'eau dans les immeubles commerciaux et le chauffage des locaux et de l'eau dans les habitations. Dans le scénario de référence, seules les deux premiers modes permettent de réaliser des économies significatives. Dans le scénario de prix élevé du pétrole, l'utilisation de cette forme d'énergie devient avantageuse pour chauffer les locaux et l'eau dans les immeubles commerciaux mais elle demeure coûteuse dans le secteur résidentiel.

- L'évaluation effectuée du point de vue commercial produit des résultats comparables, à savoir que les investissements les plus productifs seront vraisemblablement ceux qui touchent l'utilisation de l'énergie géothermique pour le chauffage des serres et pour la climatisation et la ventilation des mines.

- L'exploitation des ressources géothermiques risque de se développer lentement. Il faudrait continuer d'axer les politiques sur l'élaboration de projets pilotes afin d'évaluer le potentiel de cette source d'énergie et de réduire les coûts d'immobilisations, pour accroître le potentiel économique dans les provinces de l'Ouest.

- L'énergie éolienne

- Selon les coûts locaux de l'énergie et le régime des vents, il peut être démontré que l'installation d'aérogénérateurs est une façon économique de produire de l'électricité.

- L'analyse effectuée du point de vue commercial révèle que les projets rentables sur le plan économique peuvent l'être aussi sur le plan commercial sans aucune subvention gouvernementale.

- Les politiques visant l'évolution technologique dans le domaine de l'énergie éolienne sont du ressort des services publics. Il faudrait poursuivre les études et la recherche en vue de pouvoir déterminer le potentiel énergétique avec plus de précision et de stimuler la fabrication d'appareils moins coûteux et plus fiables.

- De façon générale, la mise au point de politiques destinées à stimuler le développement efficace de techniques d'économie d'énergie et de remplacement de l'énergie doit se fonder sur trois grands objectifs. Ces objectifs consistent à :

1) assurer que les prix du marché des formes classiques d'énergie (pétrole, gaz, électricité) correspondent aux coûts d'option réels des ressources;

2) assurer que les consommateurs soient bien informés des caractéristiques et des coûts des différentes options énergétiques;

3) établir des programmes appropriés d'aide financière pour la mise en application des techniques nouvelles, lorsqu'il peut être démontré qu'une telle forme d'aide produira de nets avantages économiques.

Executive Summary

- This paper evaluates the competitiveness of a selection of energy conservation and alternative energy technologies in the context of sectoral and regional energy needs in Canada. It outlines the underlying assumptions and methodology and discusses the implications of the results with regards to energy policy.

- The technologies selected for evaluation are divided into four groups: 1 - space heating devices for single family dwellings (the condensing gas furnace, the electric heat pump and the central wood furnace); 2 - technologies for process heat and electricity generation in the industrial sector (cogeneration, waste heat recovery, biomass for process steam generation); 3 - alternative transportation fuels (diesel, propane, CNG and methanol); and 4 - site-specific renewable energies (small hydro, geothermal and wind energy).

- The study adopts 1995 as the base year for the analysis of cost-competitiveness.

- A distinction is made between economic and commercial feasibility for an energy technology. A technology is economically feasible if from the point of view of the economy as a whole, it saves or produces energy at a cost which is less than the cost of conventional energy supply. The technology is commercially feasible if given the existing system of energy prices, taxes and subsidies, it represents an attractive investment from the point of view of the private or public investor. Both economic and commercial analyses are performed in this paper.

- The economic analysis of the selected technologies uses two sets of assumptions on the future shadow prices of energy, formulated around two scenarios of future world oil prices. In the "base case", the world oil price in 1995 is assumed to be roughly equivalent in real terms to the mid-1983 price. In the "high oil price case", a real increase of 50 per cent in the world price is assumed to occur between 1983 and 1995. In both cases, the prices are constant in real terms from 1995 on.

- The assumed shadow prices of natural gas and electricity for 1995, in both price cases, are higher than the present corresponding market prices. The natural gas shadow prices are estimated by using an 85 per cent gas/oil energy price parity at the Toronto city gate, in lieu of the 65 per cent ratio presently used in gas pricing. The shadow prices of electricity are based on the costs of additional generating capacity, assuming 7 per cent and 10 per cent real discount rates; these costs are assumed to be 15 per cent higher in the high oil price case than in the base case, as a result of increases not only in the price of oil, but in the prices of coal, gas and other resources.

- The commercial analysis uses the market prices of energy. We rely on a scenario whereby the mid-83 market prices of energy remain constant in real terms throughout the study horizon.

- The results of the technology assessments, and corresponding policy implications are reviewed below.

Space Heating Devices for Single Family Dwellings

- In the base case, the economic analysis shows that the condensing gas furnace is the cheapest space heating option for the 1995 home in the East and the Prairies; in British Columbia, a conventional gas furnace is more economic. The potential for the heat pump is limited to the provinces of Ontario and Quebec, in homes where air conditioning is desired. The central wood furnace is cost-effective in the Maritimes and in the rural regions where natural gas is not available.

- In the high oil price case, the cost-competitiveness of the condensing gas furnace and electric heat pump are improved. In the rural regions, the increase in the price of oil also favours wood heating.

- As an aside to the economic evaluation of the alternative space heating devices, we find reasons to question the economic competitiveness of electric space heating in the 1995 home.

- The commercial analysis suggests that the economically efficient space heating devices for 1995 are commercially implementable. We find however that if homeowners or home buyers consider too short an investment horizon in selecting a space heating system, for example 3 to 5 years, they are likely to opt for less capital intensive and less efficient space heating devices.

- The adoption of efficient space heating devices can be encouraged, in the case of new homes, by suggesting to home builders a set of energy-efficiency targets, and by making home buyers aware of desirable levels of efficiency. The selection of investments to meet the energy targets is best left to the market.

- In the home retrofit market, adjustments to the current program of furnace conversion subsidies (COSP) appear necessary in order that markets move away from conventional retrofit investments (e.g., plenum heaters or conventional gas furnaces) and towards more efficient and economic options.

Technologies for Process Heat and Electricity Generation in the Industrial Sector

- Industrial Cogeneration

- The technical potential for cogeneration in Canada amounts to some 6 per cent and 8 per cent respectively of total power and electricity production in Canada in 1981.

- The economic analysis suggests that under the base case, some 85 to 95 per cent of the technical potential could be realized at a cost lower than the cost to supply electricity from conventional means in 1995. The economic potential is reduced to some 70 to 90 per cent of the technical potential in the high oil price case.

- The economic evaluation of cogeneration projects in the wood and paper industries show that the use of biomass fuels for cogeneration can be very cost-effective.

- It is estimated that the commercial potential for cogeneration is only 50 per cent of the economic potential. The current situation of excess supply in the Canadian electrical sector and the corresponding low electricity rates charged to industrial customers delay the implementation of cogeneration projects. As the electricity surpluses are gradually used up, government incentives for cogenerators could become desirable in order to put in place the low-cost supply potential. The level of subsidy could decline over time, to eventually become zero.

- Waste Heat Recovery

- The technical potential for waste heat recovery in Canadian manufacturing and mining amounts to some 10.8 per cent of the energy consumed in the two sectors.

- The economic evaluation indicates that a good fraction of projects can displace energy at a cost lower than the base case shadow prices of oil and natural gas. The projects are made even more cost-effective in the high oil price case.

- The economic potential for waste heat recovery could be in the order of 40 per cent of the technical potential.

- Most of the economically feasible waste heat recovery projects can be shown commercially viable. But there is question as to whether or not industrial investors are taking full advantage of energy conservation opportunities. Financing packages to reduce the perceived risk of the investor can be promoted by government, at a low cost, to accelerate the adoption of the most effective projects.

- The more advanced techniques of waste heat recovery such as inter-plant methods of energy cascading are likely to demonstrate less potential in the short to medium term. But the development of the technology should be encouraged with a view to achieve long-term gains in industry productivity and competitiveness.

- Biomass Energy

- The use of biomass fuels (e.g., municipal solid wastes and/or sawmill wastes) is economically and commercially viable.

- Under the base case, the economic potential for energy-from-waste (EFW) plants (mostly municipal solid waste plants) to serve adjacent industrial customers is estimated at close to 60 petajoules per year. The economic potential increases to 68.5 petajoules per year if high energy prices are assumed, which amounts to some 7 per cent of the total oil products and natural gas consumption in Canadian industry in 1982.

- The commercial analysis shows that at present energy prices, the use of municipal solid wastes for generation of industrial steam can be financially profitable for both regional governments and industry.

- Different institutional factors delay the implementation of energy-from-waste plants. Cooperative participation is required from numerous parties, but none stands out as an active project promoter. Industrial plant owners in particular are hesitant to enter projects which entail reliance on government-owned facilities.

- The implementation of demonstration projects could be promoted by a multi-partite organization dedicated to EFW technology and project planning. Direct financial assistance from federal or provincial governments appears necessary in the short term. The required level of assistance should be expected to decrease over time as experience with early projects demonstrates the reliability and financial viability of EFW plants.

Alternative Transportation Fuels

- In the base case, gasoline and diesel are shown to be the most economic fuels for private (low-mileage) and fleet (high-mileage) vehicles, respectively. In the high oil price case, diesel becomes the cheapest fuel for both types of vehicles.

- The economic evaluation, in both oil price cases, suggests that propane and compressed natural gas (CNG) are less than competitive vis-ã-vis gasoline and/or diesel. Methanol is shown to be an even more expensive fuel. However, as for CNG, methanol demonstrates some potential for the longer term in view of the abundance of supply sources.

- At present, governments are promoting propane and CNG. Our commercial analysis indicates that the government incentives result in favourable investment returns for vehicle fleet owners who choose to convert to one of the two fuels. By comparison, the incentives for fleet owners to convert to diesel are marginal.

- We find that policy adjustments are necessary to establish a proper strategy for the introduction of alternative fuels. Provinces could revise fuel taxing policies to allow diesel to become more competitive. Federal fuel conversion programs could also be reevaluated. Funds presently allocated to the immediate commercialization of propane and CNG could perhaps be better utilized in research programs aimed at assessing and improving the long-term potential for methanol and CNG.

Site - Specific Renewable Energies

- Small Hydro

- Small hydro projects supplying 2 megawatts (MW) or more of power to adjacent industrial users can, at selected sites, be shown economically and commercially feasible.

- Few such projects have been implemented in recent years partly because of low electricity prices, and partly because of the lack of project promoters.

- To promote small hydro technology, operating responsibilities for small hydro should be delineated within provincial electrical utilities. The industrial ownership and development of small hydro projects should also be encouraged. At the federal level, the existing programs including support for remote community off-oil projects should be continued.

Geothermal Energy

- Geothermal Energy

- The technical potential for geothermal energy is geographically limited. The economic and commercial potential are further reduced by the number of potential applications and customers.

- We have considered four applications: greenhouse heating, mine ventilation air heating, commercial space and water heating and residential space and water heating. In the base case, only the first two applications are shown distinctly economic. Under higher oil prices, the commercial space and water heating projects becomes economic but the residential energy project remains expensive.

- The results are comparable in the commercial evaluation which identifies the greenhouse heating and mine ventilation air heating projects as the most likely candidates for investment.

- The development of the geothermal energy resource can be expected to proceed slowly. Policies in this area should continue to be directed at the development of demonstration projects, with the objective of estimating the resource base and reducing capital costs to achieve broader economic potential in the Western provinces.

- Wind Energy

- Depending on local energy costs, and prevailing wind regimes, the implementation of wind turbine generators for electricity production can be shown economically viable.

- The economically feasible projects can be commercially implementable without any form of external subsidy.

- The policies aimed at the development of wind energy technology are in the domain of the utilities. Studies and research should continue, to establish the resource base with increasing accuracy and to encourage the manufacture of lower-cost and more reliable hardware.

- In general terms, the economically efficient development of energy conservation and alternative energy technologies can be promoted by pursuing three broad objectives. They are:

  1 To ensure that the market prices of the conventional forms of energy (oil, gas, electricity) reflect the true opportunity costs of the resources;

  2 To ensure that the markets are made fully aware of the comparative characteristics and costs of the available energy options;

  3 To set up proper means of financial assistance for alternative energy technologies if and when such assistance can be shown to yield net long-term economic benefits.

1. Introduction

Canadians use relatively large amounts of energy. Part of our energy appetite is attributable to factors such as the climate, or the low population density. But international comparisons of energy use show, unequivocally, that it would be technically feasible for Canada to produce the same goods, and enjoy the same level of comfort while using less energy.[1]

In addition, there exists in Canada a technical potential to supply greater amounts of energy from non-conventional resources and technologies. The use of renewable resources such as biomass, (small) hydro, geothermal and wind energy could be intensified. Additional energy supplies could also be obtained from different processes, including the cogeneration of electricity in industry and the production of methanol from a variety of feedstocks.

But the technical potential to conserve or produce energy does not necessarily amount to an economic potential. For example, a home can be retrofitted to the point where it requires virtually no space heat energy, but it is likely that a fraction of the necessary investments would not be economically worthwhile. Ideally, energy conservation and alternative energy investments should be undertaken to the point where their costs per unit of energy saved or produced equal the costs to supply additional units of the displaced energy commodities.[2]

Several Canadian studies have identified and described the technologies available for the displacement of conventional forms of energy in the different end-use sectors.[3] But information as to the competitiveness of the technologies is more limited. This information is necessary in order to properly define and evaluate the strategies aimed at the efficient development and introduction of the respective technologies.

The economic assessment provides a basis for determining whether the market is adequately responding to the opportunities to conserve energy, or produce energy from alternative means. Insofar as possible, we should verify that the true economic potential of a technology, in the social sense, is reflected in a commercial, or market penetration, potential. Where this is not the case, because of some market failure, adjustments in government policy can be shown desirable in order that markets move towards the most efficient energy options.

In this paper, we propose to analyze a small subset of promising technologies to evaluate and compare their economic and commercial competitiveness, in the context of sectoral and regional energy needs in Canada. The selected technologies are divided into four groups corresponding to specific energy markets or resources.

First, we consider space heating devices for single family dwellings: the condensing (high-efficiency) gas furnace, the electric heat pump and the central wood furnace. Second, a selection of industrial energy investments are analyzed, including cogeneration, waste heat recovery and biomass waste plants for industrial steam generation. Third, we examine the available alternatives to gasoline in automotive vehicles, namely diesel fuel, propane, compressed natural gas (CNG) and methanol. Finally, small hydro, geothermal and wind energy are considered for site-specific applications.

The selective nature of our analysis is emphasized. Numerous other opportunities exist, in all sectors, to displace conventional forms of energy. But by examining a selection of technologies, we can define a general approach for encouraging the efficient development and introduction of energy conservation and alternative energy technologies.

In the next section, we outline the criteria and assumptions used in the technology evaluations. Sections 3 to 6 provide the evaluations themselves. For each set of technologies, we include an economic analysis, a commercial analysis and a discussion of the policy implications. The broad policy conclusions are given in Section 7.

2. The Framework for Analysis

In order to evaluate different sets of technologies in different sectors, and across different regions, it is necessary to adopt a consistent framework. This includes the specification of an investment horizon, the definition of a set of evaluation criteria and the formulation of a set of assumptions on the key parameters of the problem. These items are briefly reviewed below.

The Investment Horizon

The cost-competitiveness of each of the selected technologies is measured over a project-specific time horizon, with 1995 being chosen as the common base year. In light of the time lags involved in the identification, demonstration, commercialization and dissemination of new technologies, the year 1995 is believed to be the earliest time by which a significant level of market penetration can be achieved. There is evidence however, as shown in the following sections, that a number of technologies are already cost-effective at today's prices.

Economic and Commercial Assessment

The evaluation of the technologies is performed in terms of both economic feasibility and commercial feasibility.

A technology is economically feasible, or competitive, in a given region and for a given application if, from the point of view of the economy as a whole, it demonstrates a potential to provide or save energy at a cost lower than the cost of conventional energy supply. The indicator of economic feasibility which we use throughout the analysis is the supply price.

The supply price measures the cost of the technology in terms of real constant dollars per present valued unit of energy displaced, conserved or produced, over the full service life of the investment. Put another way, the supply price represents the constant unit cost of the displaced energy commodity which would cause the stream of discounted revenues (or savings) for an energy project to equal the stream of discounted costs.[4] The comparison of supply prices across different options identifies the economically feasible projects. In particular, the project supply prices are compared to the sector- and fuel-specific supply price, or shadow price, of conventional energy supply.

The supply price excludes consideration of all forms of transfer payments in order to measure real "bricks and mortar" costs alone. The resources, including capital, are valued at their social opportunity cost. The supply prices in the present paper are expressed in constant 1981 dollars and are based on real discount rates of 10 per cent and 7 per cent.

A technology is said to be commercially feasible if it meets the investment requirements of its potential private and/or public owners. Two of the most frequently used measures of commercial feasibility are the (undiscounted) payback and the rate of return on equity. These measures involve the calculation of after-tax cash flows over time horizons defined by owner-specific investment criteria. The input for commercial analysis includes assumptions on lending rates, applicable taxes and/or subsidies and future market prices of energy.[5]

The objectives of the economic and commercial analyses are different. The economic analysis aims at assessing the "desirability" of an investment from the nation's perspective whereas the commercial analysis is used to evaluate the likelihood of implementation of a project, given the market signals received, or perceived, by private and/or public investors.

The comparison of the results of the two analyses is important in identifying the policy adjustments, if any, which are necessary to promote the adoption of the most cost-effective technologies.

General Assumptions on the Costs and Prices of Conventional Energy

The key element of distinction between the economic and commercial analyses concerns the valuation of energy resources.

The economic analysis uses the shadow prices, or opportunity costs, of the energy commodities while the commercial analysis relies on the market prices of energy. The pricing practices in the Canadian energy sector are such that the two sets of values have been, and remain different. Our working assumptions for the investment period commencing in 1995 are briefly described below.

The economic analysis relies on two energy price cases, defined in large part by two different assumptions on future world oil prices.

In the base case, oil prices are assumed to remain constant in real terms throughout the investment horizon at a cost of $215 per cubic meter ($34 per barrel), 1981 $ Can. By comparison, the mid-83 cost of imported crude in Montreal was in the order of $200 per cubic meter ($31 per barrel), 1981 $ Can.[6] A high oil price case is constructed by using a 1995 oil reference price of $325 per cubic meter ($52 per barrel), 1981 $ Can.; this second value is also held constant throughout the post-1995 investment horizon. For both cases, the shadow prices of oil products (i.e., the regional "burner tip" shadow prices) are obtained by correcting the respective mid-83 market prices according to the above assumptions on the shadow price of crude oil, and by excluding all forms of taxes (e.g., gasoline pump taxes).

The shadow prices for natural gas are obtained by assuming an 85 per cent gas/oil energy price parity at the Toronto city gate.

This situates the base case shadow prices of natural gas for 1995 above the level of current market prices, but below the values which would be obtained if the current export price were used as the indicator of opportunity cost.[7] The 85 per cent price ratio is used in both price scenarios; regional and sectoral shadow prices are calculated by making a resource cost adjustment to the mid-83 market prices (excluding taxes), to reflect the higher long-term value of natural gas. It is noted that the resulting shadow prices do not include adjustments for either explicit or implicit government subsidies for gas distribution. The gas shadow prices can therefore be partly understated in terms of our total set of assumptions. We note that gas is assumed available in Nova Scotia and New Brunswick for 1995, at a shadow price equal to the estimated gas shadow price for Quebec.

The determination of a true cost or shadow price for electricity is more difficult. At present, the short-term electricity opportunity cost in most provinces is low because of excess supply capacity. However, low electricity rates, combined with other growth factors, are pushing demand upwards and hence, costs will have a tendency to increase, as the construction of new generating units becomes necessary. For analytical purposes, we have assumed that by 1995, the shadow price of electricity would equal the long-run marginal cost of generation, transmission and distribution. As an approximation of this cost, we use regional estimates of the marginal cost of electricity produced from thermal power systems. The underlying assumption is that the cost of marginal hydro sites in hydro-based grids will approach, by 1995, the cost of the most efficient thermal alternative (coal or nuclear) and that, presumably, water rentals will be collected on intra-marginal sites. The cost estimates are based on real discount rates of 7 per cent and 10 per cent. The resulting electricity shadow prices are considerably higher than the present market prices. Depending on the region, end-use sector and discount rate, the premium above the electricity market price ranges from less than 1 cent per kilowatt-hour to as much as 6 cents per kilowatt-hour. Typically, the base case shadow prices are some 30 to 50 per cent higher than the prevailing mid-83 market prices. In the high oil price case, the shadow prices are assumed to increase by 15 per cent, as a result of increases not only in the price of oil, but in the prices of coal, uranium and other resources.

The foregoing assumptions are one way of attempting to measure the opportunity cost of electricity. Another way of approaching the problem of evaluating alternatives which use electricity is to determine the electricity cost which just allows the technologies to become, or remain competitive vis-a-vis other conventional or alternative energy technologies. Extra calculations, in this break-even approach, are performed in Chapter 3 where the electricity cost parameter is particularly important.

The price assumptions for the commercial analysis are simpler. Since our main objective with this analysis is to reflect the current market conditions, we use a scenario whereby the mid-83 market prices of energy remain constant in real terms to, and beyond 1995.

The two lines of analysis of our study can be summarized as follows:

- The Economic Analysis

To measure and compare the real costs of the technologies over their full useful life, excluding taxes and/or subsidies, using an appropriate discount rate and using the opportunity costs of the resources. Two cases are defined; the base case or flat oil price case, and the high oil price case. The real discount rates are 7 per cent and 10 per cent.

In Section 3, the economic analysis also includes the calculation of break-even electricity costs, to evaluate competitive levels of electricity costs or shadow prices.

- The Commercial Analysis

To assess the market competitiveness of the technologies based on the investment criteria of public and/or private investors, including measures of undiscounted after-tax payback and rates of return on equity. The calculations rely on a single scenario of constant real energy market prices.

3. Space Heating Devices for Single Family Dwellings

3.1 Introduction

In recent years, a number of devices and measures have been proposed for reducing the costs of space heating in single family dwellings. Among the alternatives often referred to, we find the condensing gas furnace, the electric (air-to-air) heat pump and the central wood furnace. The first two devices rely on conventional forms of energy but offer significant energy conservation potential due to high energy conversion efficiencies: the condensing gas furnace consumes on average 30 to 35 per cent less energy than a conventional furnace; and the heat pump depending on climate can provide annual savings of 30 to 60 per cent over electric resistance heating. Interest in wood heating technology on the other hand is generally motivated by the potential for oil or electricity displacement in rural parts of the country.

The three aforementioned technologies were evaluated for cost-competitiveness vis-à-vis a set of so-called conventional alternatives for space heating in 1995 homes. Separate analyses were performed for the new home and home retrofit segments of the residential energy market; the results presented in this paper primarily concern the new 1995 home. The analysis is carried out across eleven Canadian cities and therefore accounts for regional differences in both the costs of energy and the level of space heat energy requirement. We assume that the new 1995 home is 30 per cent more energy-efficient than the average existing home; as an example, this sets the space heat energy requirement of a 1995 Ottawa home at 60 gigajoules per year, or roughly 2,400 litres of light fuel oil. This assumption is very conservative as it is likely that the 1995 home will be more efficient.

The regional market prices and shadow prices of energy for the base case are given in Table 1. The assumed service life of the heating equipment is 20 years. (The technical parameters for all technology evaluations in this report are given in Appendix 2.)

3.2 Economic Analysis

Base Case

The base case supply prices of the space heating options for new 1995 homes, in dollars per gigajoule (GJ) and for a 10 per cent real discount rate, are given in Table 2. The supply prices of the condensing gas furnace, the all-electric heat pump and the central wood furnace are compared to the supply prices of conventional oil and gas furnaces, and electric resistance heating. The results show wide variations across regions and space heating options, from $9.50 per GJ for gas heating in Alberta to up to $30.00 per GJ for electric heating in the Maritimes.

The condensing gas furnace is found to be the most cost-effective space heating alternative for all cities where natural gas is, or is assumed available, with the exception of Vancouver where the conventional gas furnace displays the lowest cost. In Quebec, Ontario and the Prairies, the condensing gas furnace provides supply prices ranging from $9.50 per GJ to $12.50 per GJ; this amounts to cost savings of 20 to 35 per cent over a conventional oil heating system, and of 10 to 12 per cent over conventional gas heating.

Under the base case, electric heating options are the most expensive. The supply prices for the electric resistance heating system vary from $16.25 per GJ (in Ottawa) to $36.34 per GJ (in Charlottetown), and are within reasonable range of oil or gas options in Quebec and Ontario only. In spite of the significant energy savings which it provides, the heat pump is only slightly less expensive on a supply price basis than electric resistance heating. If the air-conditioning capability of the heat pump is taken into consideration, by applying a $1,500 capital cost credit, the supply prices are found to vary from $13.00 per GJ (in Toronto) to over $20.00 per GJ (in the Maritimes); the heat pump with air-conditioning is shown to be competitive in Southern Ontario where the climate is favourable and electricity costs are low, but still relatively expensive in other regions of the country.

The supply prices of central wood heating range from $13.50 per GJ (in St. John's) to $18.25 per GJ (in Vancouver), and compare favourably to the costs of oil and electric heating in most regions. On a supply price basis, wood is considerably more expensive however than natural gas. Consequently, the competitiveness of wood as a space heating fuel is limited to the Maritimes, and to other (rural) Canadian regions where natural gas is not available.

Base Case, Lower Discount Rate

Table 3 shows the effect of a lower discount rate (7 per cent real rather than 10 per cent real) on the comparative costs of the alternatives. In view of the adjustments in the shadow price of electricity (see Table 1), the supply prices of the electricity-based options are considerably reduced. In Ontario, for example, the supply price of the electric resistance heating system decreases from $16.56 per GJ to $13.26 per GJ. However, the positioning of the condensing gas furnace as the least-cost option generally remains unchanged. In Quebec and Ontario, the supply price advantage of the high-efficiency gas furnace vis-à-vis the electric resistance heating system is in the order of 20 per cent. The only cost-effective alternative to natural gas heating in the two provinces is the electric heat pump but the potential is limited to homes where air-conditioning is desired.

High Oil Price Case[8]

Very similar results are obtained in the high oil price case. As shown in Table 4, high energy prices favour the more capital intensive and less energy intensive alternatives. This is seen for example in the case of the Vancouver home where for higher gas prices, the condensing gas furnace becomes cheaper to use than the conventional, less efficient unit. In rural areas, the increase in the price of oil also favours the wood heating alternative. The supply price margin between wood and oil heating increases to roughly 25 per cent, compared to a base case wood advantage of 10 to 15 per cent. The positioning of the heat pump also improves in all regions but, with the exception of Southern Ontario, the condensing gas furnace remains the lowest-cost alternative.

Break-even Electricity Costs

The results in Tables 2, 3 and 4 raise questions as to the competitiveness of electricity as an energy source for space heating in the 1995 home. In the Maritimes, oil and wood (in rural areas) appear more cost-effective; in other provinces, the condensing gas furnace displays a clear-cut supply price advantage over other available options. The point can be investigated further by determining the unit electricity cost (or shadow price) at which electricity-based heating options can be made competitive with oil, gas or wood options under specific energy price assumptions. The results of such an analysis are given in Tables 5 and 6.

Table 5 lists the "break-even" electricity costs for the electric resistance heating system and the heat pump under the base case. The results indicate that electric resistance heating can be competitive with other conventional alternatives in 1995 if residential electricity costs (calculated at a 10 per cent discount rate) are less than 5 cents per kilowatt-hour (kWh) in the Maritimes, 4 cents per kWh in Quebec and Ontario, and roughly 3 cents per kWh in the Prairies and in British Columbia.

The break-even costs are lower if electric resistance heating is evaluated against the least-cost space heating option in each region. In this case, we find the break-even cost in most provinces to be roughly equal to the prevailing market price of electricity, as shown in Table 1. In Quebec and Ontario for example, electricity costs cannot exceed 3.5 cents per kWh if electric resistance heating is to compete with the condensing gas furnace, under base case assumptions on natural gas shadow prices.

In most regions, the heat pump requires even lower break-even costs than the electric resistance heating system, except if its air-conditioning value is taken into account. For instance, in a Toronto home where central air-conditioning is desired, the heat pump can be competitive, under the base case, if electricity costs are less than 4.5 cents per kWh.

The break-even costs are of course higher in the high oil price case. As shown in Table 6, it would appear necessary however, with few exceptions, to consider a ceiling of 4 to 4.5 cents per kWh on the cost of electricity to allow for a cost-effective penetration of electricity-based heating options in the 1995 market.

General Comment

The break-even electricity costs given in Tables 5 and 6 can be put into perspective by considering the structure of electricity prices in Canada. As mentioned above, we have found the break-even costs to be comparable with present electricity prices. In turn, these prices are generally considered to be lower than the long-run marginal cost of electricity. The differences between present prices and long-run costs are explained in some provinces by the current surplus of electricity supply and, more generally, by the financial structure of Canadian electrical utilities, the costing and pricing rules adopted by the electrical industry, and the low prices and royalties paid by utilities for resources such as water, coal and natural gas used in electricity generation.

Under these considerations, we can suspect that our estimated break-even costs are lower than the future opportunity cost of electricity, suggesting that electricity would be less than competititve in the 1995 space heating market. This of course tends to confirm that natural gas heating and the condensing gas furnace are likely to be the most economical choices for the residential sector in most regions of Canada.

The above result holds very important implications for provinces such as Manitoba, Ontario and Quebec. We note that it is subject to the above qualifications:

- The relative cost-effectiveness of space heating options varies considerably with the level of space heat energy requirement. Electric heating options for example become relatively cheaper as heat loads become lower. In particular, electricity is among the few practical heating alternatives for super energy-efficient homes. Since the rate of construction of these homes can be expected to accelerate in forthcoming years, electricity-based heating could become economic in a larger number of homes, over time.

- The use of electricity for space heating can be made more cost-effective through the implementation of hybrid (electricity-oil, electricity-wood) heating systems. Depending on the use of the backup source and the resulting effect on the load curve of the utility, the costs of the hybrid system can be considerably lower than the cost of an all-electric system. The hybrid application is particularly well suited to the home retrofit market where the original furnace can serve as back-up to the add-on unit (heat pump or plenum heater). It is less certain however whether the hybrid concept can be economically developed in the new home market.

- A better assessment of the comparative effectiveness of electricity and natural gas in space heating could be gained through a more detailed analysis of the economic costs of the respective fuels in different regions of Canada. In terms of natural gas shadow pricing, this would include careful evaluation of distribution costs, using assumptions on pipeline capacity factors specific to space heating demand profiles. For example, higher energy costs could be imputed to the condensing gas furnace in view of the lower utilization factor.

In summary, the comparative evaluation of space heating alternatives for 1995 homes identifies a significant potential for technologies which either conserve energy (the condensing gas furnace, the electric heat pump) or rely on an alternative form of energy (the central wood furnace). The condensing gas furnace is found to be a promising space-heating alternative for Quebec, Ontario and the Prairies. The heat pump is relatively expensive but in Quebec and Ontario, it may adequately compete, on an economic cost basis, with natural gas heating in homes where air-conditioning is desired. In rural areas of the country, the central wood furnace provides an alternative which is competitive with both oil and electric heating.

Similar conclusions emerge from our analysis of the 1995 home retrofit market. Off-oil conversions to the condensing gas furnace or to central wood heating are found very cost-effective. By comparison, conversions to the conventional gas furnace provide lower economic benefits, and conversions to the electric plenum heater (as an add-on) are found uneconomic. In the short term however, the results may be more ambiguous due to existing surpluses in electricity and gas supplies. For instance, investments in electric plenum heaters may be justified in the short run if it can be shown that they can be paid back, in the social sense, over a short period of time. This may be the case in Eastern Canada, in view of the low short-term electricity cost (presently limited in some cases to system operating costs), and in view of the extra energy supply flexibility which can be gained by adding plenum heaters onto existing oil furnaces.

3.3 Commercial Analysis

An exception is made for the commercial analysis of space heating alternatives for new 1995 homes. Rather than to calculate paybacks and rates of return on equity, which do not apply well to this problem, we calculate a set of "private" supply prices. The private supply price estimates the costs (capital, maintenance and energy) incurred by a homeowner for the use of a system over a specific investment horizon and under a specified set of assumptions on the future market prices of energy. The supply prices are expressed in constant (1981) dollars per present valued unit of heat energy; the calculations provided here are based on a real private discount rate of 3 per cent and on a scenario of constant real energy market prices, at mid-83 levels as given in Table 1.

The results of the private supply price analysis for a 20 year investment period are given in Table 7. Since the market prices of energy are lower than the assumed shadow prices, the private supply prices are lower than the supply prices calculated in the economic analysis. The supply prices in Table 7 range from $6.00 per GJ for gas heating in Regina to $23.54 per GJ for electric heating in Charlottetown.

The results of the evaluation appear encouraging with regards to the commercial potential for the condensing gas furnace, the heat pump and the central wood furnace. As in the economic analysis, the condensing gas furnace emerges as the least-cost space heating alternative in most regions, with supply prices ranging from $6.00 per GJ in the Prairies to some $9.00 per GJ in the East. The negative effect of low natural gas prices, i.e., below the shadow prices defined in the economic analysis, on the competitiveness of the high-efficiency furnace vis-à-vis the conventional unit is offset by the positive effect of a low discount rate (3 per cent real as opposed to 7 or 10 per cent real in the economic analysis).

Electric options are found cheaper than oil heating in all provinces, with the exception of Prince Edward Island; this reverses the general result observed in the (base case) economic analysis. The private supply prices for the electric resistance heating system are below $11 per GJ in most regions whereas the costs of oil heating range from $13 per GJ to $15 per GJ.

Heat pumps, with air-conditioning are either competitive or near-competitive in most provinces. It is interesting to note that in Newfoundland, Nova Scotia and New Brunswick, the prices of electricity are such that the heat pump, even without the air-conditioning credit, becomes cheaper on a private supply price basis than conventional oil heating.

Finally, the commercial potential for wood is limited to the Maritime provinces where, at the exception of New Brunswick, it remains the least-cost alternative for rural homes; in other provinces, both gas and electricity are cheaper.

The above results suggest that the private interests of the homeowner with regards to the choice of a home space heating system are fairly consistent with criteria of economic efficiency, i.e., the most economically profitable space heating options are also likely to minimize consumer costs. However, the market performance of the most cost-effective solutions may be less than could be expected. First, the selection of a heating system for a new home is often left to the builder; this may result in the installation of low capital cost but energy intensive alternatives. A second important factor is the investment horizon of the home buyer, in selecting the space heating system, which is generally less than the 20 years which we have assumed.

The effect of the time horizon is shown in Table 8 which repeats the private supply price analysis but for an investment horizon of 5 years. The results show that under the assumption of a short investment period, the condensing gas furnace, the central wood furnace and the electric heat pump are entirely priced out, at the benefit of conventional oil, gas or electric resistance heating. This last result is more consistent with the situation which currently prevails in the new home market. The same applies to the home retrofit market where homeowners may seek short paybacks and not necessarily minimization of long-run costs.

3.4 Implications for Policy

The condensing gas furnace is an economically and commercially viable option for space heating in most regions of Canada. In selected regions, the heat pump and central wood furnace also demonstrate an economic and commercial potential. To date however, the market penetration of these technologies has been limited.

The means by which the adoption of the most cost-effective space heating options can be encouraged vary according to the structure of the target market. In terms of the new home market, the efforts need to be directed at both the building industry and the potential new home buyers. Recognizing that the goal of an energy program is not to impose the implementation of specific technologies but rather to contribute to the reduction of energy costs, the most useful approach consists of suggesting to home builders a set of energy efficiency targets, and of making home buyers aware of desirable efficiency levels. The energy targets can be met either through construction of thermal-resistant homes and/or through installation of efficient space heating devices. The selection of the least-cost package of investments for meeting the energy targets is best left to the market. The role of government can be limited to the identification of reasonable targets (they should tend to the economic limit) and to the dissemination of information for builders and home buyers on the costs and benefits of energy conservation and/or alternative energy investments in new homes.

The situation is different in the home retrofit market where the decisions are taken by the homeowner alone. In recent years, the federal government has played an aggressive role in this market through the Canadian Oil Substitution Program (COSP). The program aims at accelerating the conversion of oil heating systems to either electricity, gas or wood alternatives by providing taxable grants of $800 to eligible homeowners. Since its inception, the program has had considerable success in terms of reducing the share of oil in residential energy demands but it has not necessarily encouraged the adoption of the most efficient solutions. In order to achieve this goal, conversion grants to homeowners could be replaced by research and development funds allocated to industry to promote, in early stages of development, the production and marketing of alternative technologies such as the condensing gas furnace, the heat pump and the central wood furnace.

The potential for alternative energy technologies in residential space heating can be realized partly, but not fully through normal market mechanisms. Government involvement appears necessary to provide technical and/or financial assistance to the building and space heating hardware industries as they become involved with new, energy-efficient technology, and to ensure that homebuyers and homeowners are well informed of the relative costs and benefits of the available options.

4. Technologies for Process Heat and Electricity Generation in the Industrial Sector

4.1 Industrial Cogeneration

4.1.1 Introduction

Cogeneration is the simultaneous generation of electric power and useful heat from a single plant and energy source. In North America, the technology has steadily declined in importance since the 1880s when 58 per cent of total power needs was generated in industrial power plants and half of this was cogenerated. At present, as shown in Table 11, it is estimated that the fraction of total electricity produced from cogeneration in Canada is in the order of 1 per cent.

Our evaluation of the potential for cogeneration in Canada uses a set of data collected by Acres Shawinigan in 1979, and updated in 1982.[9] It focuses on the most promising technology, which uses a high pressure steam boiler equipped with a back pressure steam turbine for electricity generation. This technology is flexible in the sense that the boilers can be designed to burn any or more of several fuel types including oil, gas, coal, wood or other forms of biomass. The study data base is limited to industrial processes and plants requiring at least 45,000 kilograms of steam per hour. Economic and commercial analyses were performed for 202 industrial plants across 8 provinces and 10 two-digit S.I.C. industry groups. This represents approximately 60 per cent of all industrial plants in Canada requiring the specified amount of steam in their process operations.

Table 9 lists the regional energy market prices and shadow prices used for the base case evaluation of industrial energy investments. For cogeneration, natural gas is assumed as incremental fuel for 1995 in all provinces; the data base does not include projects from Newfoundland and Prince Edward Island, where diesel would be the likely choice for incremental fuel. In the lumber and pulp and paper industry, we also consider the use of logging residues and of on-site biomass wastes. The cost of logging residues includes collection and transportation; the cost of on-site wastes is assumed zero although actual costs can be either positive, if there exists a market for the waste, or negative, if disposal costs are avoided.

4.1.2 Economic Analysis

Base Case

The results of the supply price analysis for the 202 cogeneration projects are summarized in Table 10. The data summary includes the distribution of capacity and energy production by supply price and region; the supply prices are based on a 10 per cent real discount rate and are expressed in cents per kilowatt-hour (1 cent per kWh corresponds to slightly less than $3 per GJ).

The results indicate that under the base case, 97 per cent of the technical electricity production potential in the 202 industrial plants or roughly 17,000 gigawatt-hours (GWh) per year can be realized at a supply price under 4.5 cents per kWh; 86 per cent can be produced at a supply price under 3.5 cents per kWh. The corresponding capacity is also significant; the total technical potential is 2,450 megawatts (MW) for the 202 projects, with 80 per cent of total capacity providing electricity costs below 3.5 cents per kWh.

Based on our sample of projects, the greatest cogeneration potential exists in Ontario, Quebec and British Columbia. The three provinces combined comprise over 70 per cent of the total capacity and electricity production potential.

The results of the analysis for the 202 sample projects are extrapolated in Figure 1 to provide a potential supply curve for cogeneration, relating supply prices with the quantity of electrical energy, in GWh per year, which could be supplied at these prices from cogeneration facilities in Canada. The supply potential, estimated at 29,400 GWh per year (or 4150 MW), relates to a full cycle of industrial boiler replacements and can thus be considered as implementable over a period of 20 to 25 years.

Figure 2 depicts the potential supply curves for cogeneration in the lumber and pulp and paper industries in Canada, under different assumptions on the choice of incremental fuel. The effect of using lower cost waste fuel in place of natural gas is significant. If natural gas is used as incremental fuel, 26 per cent of the projects in the forest products industry show supply prices under 3 cents per kWh. With the use of logging residues and mill wastes, the fraction of such low-cost projects increases to 94 per cent, and 100 per cent, respectively. The total technical potential for cogeneration in the two industries amounts to over 11,000 GWh per year (or 1200 MW), or 37 per cent of the potential for the total industrial sector.

As shown in Tables 11 and 12, the technical potential for cogeneration in industry amounts to 5.5 per cent and 8.8 per cent respectively of the total capacity and electricity production in Canada. This is five times greater than the fractions of power and energy presently supplied from cogeneration in Canadian industry. Tables 11 and 12 also provide estimates of the economic potential, which is established by the capacity and production potential of cogeneration projects providing supply prices below the corresponding regional shadow price of electricity for the industrial sector. Under the base case, and using a 10 per cent real discount rate, virtually all of the 202 projects evaluated are found economic. The extrapolated economic potential for Canada is 3,930 MW, or 28,600 GWh per year.

Base Case, Lower Discount Rate

The effect of variations in the discount rate on the competitiveness of cogeneration technology is mainly felt through the corresponding changes in the costs of conventional electricity generation (e.g., hydro, nuclear, thermal) which in turn result in changes in the shadow prices of electricity; the effect on the supply price of cogeneration projects is limited since the capital cost portion of total project costs is relatively small. As a rule, a lower discount rate results in lower electricity shadow prices (as shown in Table 9) and thus in a reduced potential for cogeneration. For a discount rate of 7 per cent real, the economic potential is estimated at 3,560 MW, and 26,200 GWh per year compared to 3,930 MW and 28,600 GWh per year for a 10 per cent real discount rate, not a significant decrease; the comparison is shown in Table 13.

High Oil Price Case[10]

Assumptions on energy shadow prices directly affect the supply price of cogeneration projets. As shown in Table 11 and Figure 1, the supply price of the average project increases by approximately 1 cent per kWh under higher oil and gas prices; the percentage change in cogeneration supply prices with respect to a percentage change in the cost of the incremental fuel (e.g., natural gas) is in the order of .6. However, because the electricity shadow prices are assumed to increase by 15 per cent in the high oil price case, the economic potential for cogeneration remains relatively unchanged. The effect of high fuel costs is to eliminate marginal projects with little capacity and production potential. The larger projects remain competitive. As shown in Table 13, the estimated economic potential for a 10 per cent real discount rate amounts to 3,730 MW, or 27,335 GWh per year.

High Oil Price Case, Lower Discount Rate

The effect of high energy prices on the cogeneration potential is more significant if it is combined with the effect of a lower discount rate. For a 7 per cent real discount rate, the capacity and production potential in the high oil price case decreases to 2,850 MW, or 20,900 GWh per year. This represents 70 per cent of the total technical potential. As shown in Table 13, the fraction is highest (i.e., 100 per cent) in New Brunswick and Nova Scotia and lowest (i.e., 40 per cent) in Ontario.

The economic analysis of cogeneration indicates that a considerable supply of power and electricity can be made available through implementation of cost-effective cogeneration projects. For larger projects, economic feasibility is relatively ensured despite uncertainty in the value of the social discount rate and the future course of energy prices. It is shown below that actual implementation of the projects is subject to a number of financial and institutional considerations.

4.1.3 Commercial Analysis

The decision to implement a cogeneration project in an industrial plant is the responsibility of the plant owner. Important criteria are the investment payback and the project rate of return on equity (ROE). These two measures of financial feasibility were estimated for the 202 projects included in the study data base. The commercial analysis uses the following assumptions:

- the investment horizon for purpose of ROE calculation is 25 years;

- the project is financed by 50 per cent equity funds and 50 per cent debt - the debt portion of the investment is repaid over a period of 8 years and carries a real cost of 4 per cent per annum;

- the capital cost portion of the project is written off on a 3 year straight line basis;

- the corporate rate of income tax (50 per cent) is applied to all net project revenue, positive or negative;

- the investment cost is reduced by a 7 per cent investment tax credit and, in the case where wood waste is used as incremental fuel, an investment grant from the federal government's Forest Industry Renewable Energy program (FIRE), amounting to 20 per cent of the total capital cost;

- energy market prices (at mid-83 levels as given in Table 9) and operating and maintenance costs are level in real terms throughout the investment horizon;

- surpluses in electricity production are sold back to the utility at 50 per cent of the market price.

A first estimate of the commercial potential for cogeneration is given by applying a 5 year payback target to all projects. Under this requirement, 45 per cent of the total capacity of the 202 projects (1,100 MW) and 47 per cent of the total production potential (8,220 GWh per year) can be considered as commercially feasible, as shown in Table 14. The commercial potential is relatively small in Quebec and British Columbia, i.e., in the order of 30 to 35 per cent of the technical potential, but approaches 90 per cent in New Brunswick and Saskatchewan where electricity prices are higher.

The commercial potential is roughly equivalent if a 20 per cent nominal ROE is used as the hurdle rate. (The assumed long-term annual inflation rate is 6 per cent.) It decreases to roughly 20 per cent of the total technical potential if industrial investors apply a 30 per cent nominal ROE criterion for project implementation.

The use of biomass wastes as incremental fuel leads to very favourable financial returns. Calculations performed for 66 cogeneration projects in the pulp and paper industry show that the portion of total cogeneration supply potential available at project paybacks of 5 years or less increases from 49 per cent when natural gas is used as incremental fuel to 89 per cent and 99 per cent if logging residues and on-site wastes are utilized, respectively (see Table 15). The financial benefits of using biomass wastes are due in part to the investment grant received from the federal FIRE program.

4.1.4 Implications for Policy

Large industrial steam users in Canada could supply up to 4,000 MW of power and 29,000 GWh of annual energy through implementation of cogeneration technology. Up to 90 per cent of this technical potential can be considered as economic from the perspective of competitive supply prices. However, except in the pulp and paper industry, less than 50 per cent of the full potential is implementable from the market perspective of project viability. Moreover, a number of financially feasible cogeneration projects are not undertaken; the fraction of implemented supply is presently as low as 20 per cent of total potential. Accordingly, policy efforts should aim at reducing the gaps between economic and commercial potential and between commercial and implemented potential.

A first factor to consider is the relationship between the market price and long-run cost of electricity. As argued in the previous section, the present market prices of electricity fall short of long-run marginal costs. Hence the true value of electricity savings is understated in private cogeneration evaluations. Also, revenues from the sale of excess power and energy to the utility are heavily discounted by the pricing and buying practices of the electrical industry. A widening of the scope for cogeneration in Canadian industry would therefore be an important consequence of a revision of electricity pricing policy.

Low electricity prices in Canada are explained in part by the considerable supply surplus which presently exists in some provinces. Any justification for additional cogeneration facilities may therefore appear difficult in the short- to medium-term. However, it is important to recognize that investments in cogeneration are generally linked to the replacement of industrial boilers. This means that a cogeneration project in a given industrial plant can be economically viable only when undertaken at the time of the replacement of boilers. Accordingly, the postponement of a cogeneration project can result in delays upwards of 20 to 25 years if boilers are replaced by conventional, low-capacity units, not capable of generating the amount of steam required for cogeneration. This suggests that it may be worthwhile to introduce incentives for cogeneration as the electricity surpluses are used up, in order to gradually put into place the low-cost supply potential.

The incentive to cogenerators can take different forms. The currently available 3 years accelerated write-off is one example. Capital grants, such as these currently provided by the FIRE program for biomass energy projects, may also be considered. Ideally, the financial incentives should be such that the economically feasible projects, under consideration of long-term electricity costs, become commercially competitive. The stucture of the incentives package should therefore be flexible enough so as to adapt to changing conditions over time, and across regions and even industries. For example, the pulp and paper industry would likely require less incentive than the food and beverage industry.

It is necessary to ensure that industrial plant managers and financial managers become fully aware of cogeneration investment opportunities. This requires dissemination of information on latest equipment, processes and relevant case studies. Our analysis indicates that if a greater fraction of industrial plants were to implement cogeneration technology, the long-run cost of electricity could be lowered and the flexibility of electricity supply increased because of the addition of smaller increments to the total availability of power and energy.

4.2 Waste Heat Recovery

4.2.1 Introduction

It is estimated that some 36 per cent of the energy input in Canadian manufacturing and mining is rejected into the atmosphere in the form of waste heat streams.[11] It is also estimated that 30 per cent of the waste heat streams, or 11 per cent of total energy inputs, could be recovered for application in the industrial or other end-use sectors.[12] This amounts to a technical potential for energy recovery of over 180 petajoules (PJ) per year, or the equivalent of some 80,000 barrels of oil per day.[13]

The numerous waste heat recovery alternatives may be classified as in-plant, inter-plant and inter-sector energy cascading technologies. In-plant technologies are the most widely applicable -- these include such measures as:

- steam traps to recover energy in steam condensate for return to the boiler;
- heat exchangers, including boiler economizers to pre-heat combustion air and boiler feedwater with flue gases;
- waste heat recovery boilers;
- vapour recompression;

- heat pumps for low temperature applications of waste heat.

Cogeneration is a special case of waste heat recovery in electricity generation and was discussed in Section 4.1.

Inter-plant and inter-sector methods of waste heat recovery are far less common as these typically face institutional and locational difficulties (e.g., the need for a planned integrated energy complex) and/or economic hurdles in the form of high-cost transportation of waste heat streams. Examples of such techniques include thermal and nuclear electric power generation plants which provide low temperature waste heat to industrial plants, and diesel-powered electric plants in northern communities which provide waste energy to district space heating systems.

The analysis presented in this paper concerns the more common methods of in-plant waste heat recovery as these techniques have the greatest potential to reduce industrial energy consumption; inter-plant and inter-sector applications of energy cascading are excluded from the quantitative analysis. Data on 31 waste heat recovery projects were assembled.[14] The projects cover a range of industries including food and beverage, pulp and paper, industrial chemicals, glass products, metal mines and transportation equipment. The project investment costs are relatively modest; the average cost is below $120,000 with corresponding annual energy savings (natural gas or fuel oil) averaging 37,000 gigajoules (GJ) per year.

The economic and commercial evaluations of the 31 waste heat recovery investments are based on the shadow prices and market prices of energy for the industrial sector as given in Table 9. The assumed project life, in all cases, is 15 years.

4.2.2 Economic Analysis

The supply price analysis of waste heat recovery projects identifies a sizeable potential for energy cost savings in industry. As shown in Table 16, the average project supply price for a 10 per cent real discount rate is $0.84 per GJ. This corresponds to a supply price of 3.1 cents per cubic meter of natural gas, or 3.5 cents per litre of heavy fuel oil By comparison, the assumed shadow price of natural gas for the industrial sector in Alberta for 1995 is 14 cents per cubic meter, the current market price is 7 cents per cubic meter. The largest fraction of waste heat recovery investments (26 out of 31) yield supply prices of less than $1.00 per GJ; the supply prices of the remaining projects are below $5.00 per GJ which is slightly less than the base case shadow price of natural gas for Quebec.[15]

The aggregate economic potential for waste heat recovery is difficult to evaluate. Estimates from a previous study would suggest some 4.5 per cent of total industrial energy consumption, for just the short term.[16] This amounts to some 75 PJ per year, or 40 per cent of the estimated technical potential, as shown in Table 17. Analysis of the responsiveness of this potential to parameters such as the discount rate or the level of energy shadow prices would require more detailed and comprehensive data. It is clear from the supply price analysis of the 31 sample projects that an important fraction of the economic potential relates to quick payback and low risk investments. Projects demonstrating marginal economic benefits tend to belong to the category of inter-plant/inter-sector applications of waste heat recovery which are not included in the above estimate of the economic potential.

4.2.3 Commercial Analysis

The commercial potential for waste heat recovery is evaluated by examining four representative investments. The financial feasibility of the four projects is assessed for different regions of Canada and thus for different levels of natural gas and heavy fuel oil prices. The analysis assumes full equity financing (capital outlay is less than $120,000 in all four cases) and a 15 year investment horizon. The fiscal setting for investment is as described in the section on cogeneration; the rate of corporate income tax (50 per cent) is applied to all project revenues and losses, the investment is written off over a three year period and a 7 per cent investment tax credit is claimed against company revenue. (FIRE grants are not applicable.)

The four projects are characterized by respective supply prices of $0.68 per GJ, $0.91 per GJ, $3.08 per GJ and $4.58 per GJ. As shown in Table 18, this ranking of the projects in terms of cost-effectiveness holds in the commercial analysis as well as in the economic analysis.

If heavy fuel oil is displaced, all but the most expensive project achieve the 5 year payback target; the cheapest project is paid back in less than 2 years. The displacement of natural gas provides less financial benefits in view of the lower fuel price. Nonetheless, the two most effective projects yield paybacks of 3 years or less and rates of return on equity of over 25 per cent. These two projects, with supply prices of $0.68 per GJ and $0.91 per GJ are representative of the bulk of the 31 waste heat recovery investments that we have sampled (refer to the supply price distribution in Table 16).

The commercial evaluation of the four sample projects suggests that the existing system of taxes and incentives is sufficient to ensure the financial viability of a large fraction of waste heat recovery investments. Accordingly, a good part of the economic potential indentified in Table 17 could be expected to be realized before 1995. Yet, there remains question as to whether or not industrial investors are actually taking advantage of the available energy conservation opportunities. Payback requirements for cost reduction investments are often less than 5 years (e.g., 12 to 18 months) and financial constraints often delay project implementation. As shown below, simple and inexpensive tools can be developed by government to correct this situation and to accelerate the adoption of cost-effective waste heat recovery technologies.

4.2.4 Implications for Policy

It is practical for policy purposes to distinguish between two broad classes of waste heat recovery investments. The first class or "first generation" of investments includes the projects which meet the requirements of both economic and commercial feasibility, and which are relatively simple in application. The second class or "second generation" of investments concerns the more advanced applications of waste heat recovery such as inter-plant/inter-sector methods of energy cascading. Typically, these projects yield marginal economic and commercial benefits and demonstrate limited potential for the short term. The first generation/second generation breakdown of waste heat recovery investments suggests a need for two distinct sets of policy instruments.

With regards to the first generation of investments, the policy objective is to ensure that the established low-cost energy conservation potential is fully exploited. "Incentive Financing" programs can be put into place to achieve this goal. Basically the approach involves the set-up of an institutional framework for allocation of investment funds to industry. Loans are granted to industrial plant owners with the provision that the loan repayments, in any one year, cannot exceed the value of the energy savings resulting from the implementation of the projects. In effect, the lender (a bank, financial institution or government corporation) becomes the risk-taker while the plant owner collects the net value of the energy savings, over and above the full amount of loan repayments. In return for the risk which is incurred, the lender may charge a higher lending rate, i.e., a rate sufficient to make the venture commercially profitable. Incentive financing programs supported by government could help fill a perceived gap in institutional banking and, to the extent that the projects are carefully selected, could provide benefits to all parties involved, while contributing to accelerate the adoption of cost-effective waste heat recovery projects. It is noted that a subsidiary of the federal government's Canertech corporation, Canertech Conservation Inc., has set up a program of incentive financing for the commercial and industrial sectors.

In terms of the second generation of waste heat recovery investments, the needs are considerably different. Efforts should be directed at the dissemination of information and the sponsoring of demonstration programs. Sufficient attention should be given to inter-plant/inter-sector methods of energy cascading and to prospects for the development of energy-integrated industrial complexes. Through participation of industry and of all levels of governments, long-term gains could be achieved in the form of increased productivity and industry competitiveness.

In summary, the success of government policy in the field of industrial energy conservation depends upon the capacity of the respective programs to address specific needs (e.g., research and development, demonstration, marketing, financing) at different levels of development and implementation of the technologies. The first generation/second generation breakdown of waste heat recovery technologies serves as a useful, although simplified, characterization of the wide range of investment opportunities open to the Canadian industrial sector.

4.3 Biomass Energy

4.3.1 Introduction

Biomass is defined as the set of resources comprising unfossilized materials of biological origin. It refers to such diverse materials as wood, peat, manure, vegetation and the organic portion of municipal solid waste (MSW), for example, food and paper. The energy embodied in these materials represents the most promising renewable energy base for Canada (hydro excluded). It can be extracted through a variety of methods and processes and can serve a wide range of end-use applications. Examples discussed in other sections of this paper are the use of wood for residential space heating (Section 3) and of methanol, derived from wood or other substances, for gasoline substitution in the transportation sector (Section 5). This chapter examines a third potential application of biomass energy technology namely the generation of industrial process heat from wood wastes and/or municipal solid wastes.

An energy-from-waste (EFW) plant is evaluated for the supply of process steam to an adjacent industrial user. The prototype plant is designed to process any mixture of municipal solid waste and sawmill wastes (bark, shavings and sawdust) at a rate of 180 tonnes per day. The input capacity corresponds to a steam production potential of 20,000 kilograms per hour, a quantity considered as representative of medium-sized industrial users. In effect, the size of the plant could be adjusted (with roughly proportionate adjustment in costs) to suit the specific requirements of potential steam customers.1/

The project evaluation uses the shadow prices and market prices of energy for the industrial sector as given in Table 9. The cost (and price) of sawmill wastes is assumed limited to the cost of transportation and is estimated to range between $12 per tonne and $20 per tonne. For MSW, credits of $4 per tonne to $12 per tonne are applied to reflect the value (avoided cost) of waste disposal. The assumed project life is 20 years.

4.3.2 Economic Analysis

Base Case

The energy-from-waste plant displaces natural gas or heavy fuel oil used in conventional steam generation. Accordingly, the economic feasibility of the project is achieved if the estimated supply price per energy unit of displaced oil or gas is less than the regional shadow prices of these industrial fuels.

The supply price for the EFW plant varies according to the mix and cost of the MSW and sawmill waste input. As shown in Table 19, the project supply price, for a 10 per cent real discount rate, ranges from \$2.96 per gigajoule (GJ) to \$3.76 per GJ if a 100 per cent MSW input is assumed; from \$4.57 per GJ to \$4.84 per GJ if the plant uses a 50-50 mix of MSW and sawmill wastes; and from \$4.84 per GJ to \$5.64 per GJ if the waste is entirely supplied from a sawmill. The differences in supply price across the fuel mixes are explained by differences in both the cost of the feedstocks (MSW is considerably cheaper than off-site wood wastes) and the cost of the related equipment and processing (costs are lower for use of wood-based fuels).

The project supply prices compare favourably to the base case shadow prices of heavy fuel oil and natural gas, as given in Table 9. (If expressed in terms of dollars per unit of fuel displaced, the supply prices for the project range from 12 to 24 cents per litre of heavy fuel oil, or 11 to 21 cents per cubic meter of gas - see Table 19.) The 100 per cent MSW plant is economically viable in all regions. At even the lowest estimate of avoided landfill cost (\$4 per tonne of waste) it cost-effectively displaces natural gas or heavy fuel oil. By comparison, EFW plants using high fractions of sawmill waste show more limited potential. For a 50-50 fuel mix, or a 100 per cent sawmill waste input, the competitiveness of the EFW plant is generally limited to Quebec, Ontario and the Maritimes and depends on the cost of waste supply. For wood-based projects, this cost is determined in large part by the distance separating the steam plant from the supplying sawmill.

The estimation of the economic supply potential first requires an approximation of the technical potential. This technical potential has been estimated by relating provincial and sub-provincial supplies of MSW and sawmill wastes to corresponding (regional) demands for industrial process steam. As shown in Table 20, the nationwide technical potential is estimated at 68.5 petajoules (PJ) of secondary energy per year. (By comparison, the consumption of oil products and natural gas in Canadian industry in 1982 amounted to 980 PJ.)[18] The EFW supply potential corresponds to the steam output of some 140 plants of 180 tonnes per day capacity. The 100 per cent MSW plant is the most widely implementable with a total supply capacity of 55.7 PJ per year. The potential for off-site use of sawmill wastes is comparatively small since the resource is highly concentrated in few and often remote areas. It is estimated that EFW plants using a 50-50 MSW/sawmill waste mix and 100 per cent sawmill waste could provide 7.7 PJ and 5.1 PJ in annual steam energy, respectively.

The base case economic potential is estimated at 58.7 PJ per year. As shown in Table 20, this includes the full technical potential for steam generation from MSW plants (55.7 PJ per year), and 50 per cent of the available energy from wood-based projects in Quebec and Ontario (3.0 PJ per year).

Base Case, Lower Discount Rate

The competitiveness of the EFW plant is improved slightly if a lower discount rate is used. The use of a 7 per cent rather than 10 per cent real discount rate results in a reduction in supply price of 10 to 20 per cent, or roughly $0.50 per GJ. The change has little effect on the economic supply potential.

High Oil Price Case[19]

If the supply prices for the EFW project, as shown in Table 19, are compared to the energy shadow prices in the high oil price case, the EFW project can be shown cost-effective in all regions and for any feedstock mix. As a result, the economic potential becomes equivalent to the commercial potential, or 68.5 PJ per year.

In summary, it is found that the MSW plant is economic under a fairly wide range of assumptions. Energy-from-waste plants using high fractions of wood wastes are more marginal in terms of both cost-effectiveness, and supply potential.

4.3.3 Commercial Analysis

The evaluation of commercial feasiblity is limited to the 100 per cent MSW plant. It is assumed that the plant is owned and operated by a municipal or regional government and that the steam is purchased by an industrial customer. The assumption of public ownership precludes consideration of income tax, tax credits or capital cost allowances. However, the project is eligible for a investment grant from the federal government's FIRE program, amounting to 20 per cent of the total capital costs. The assumed debt-equity ratio is 80-20; the debt carries a real annual cost of 4 per cent and is repaid over a 20 year period.

The project revenues are determined by the steam price negotiated between the supplier and user, and by the avoided cost of conventional waste disposal, or "tipping fee". The issue of steam pricing has received much attention in recent feasibility studies. It has been noted that in view of perceived elements of novelty and risk, the potential customers of an EFW plant typically require a discount off the cost of their "make steam" option as a condition for participating in the project. Accordingly, the revenues from the sale of steam in the present analysis are estimated by applying a 20 per cent discount to the market value of displaced oil or gas. The market prices of the displaced fuels are assumed to remain constant, in real terms at mid-83 levels, as given in Table 9. As in the economic analysis, the tipping fees are assumed to range from $4 to $12 per tonne of waste.

It is assumed that the EFW investment is sufficiently attractive from the point of view of the municipal investor if the nominal rate of return on equity exceeds 15 per cent (9 per cent real, i.e., 5 per cent above the assumed borrowing cost). As shown in Table 21, this requirement can be met in a number of cases. If heavy fuel oil is displaced, the project return on equity exceeds 25 per cent under the full range of tipping fees in all provinces except British Columbia. In British Columbia, the project is viable, for oil displacement, if the tipping fee is higher than $4 per tonne of waste.

The financial evaluation is less favourable if natural gas is assumed displaced. The project is not viable in Alberta where natural gas prices are lowest. In Manitoba, Saskatchewan and British Columbia, the investment yields the required rate of return only if tipping fees are higher than $6, $10 and $8 per tonne, respectively. In the Maritimes, Quebec and Ontario, the project remains financially feasible for natural gas displacement at even the lowest estimate of avoided landfill cost.

In view of the sensitivity of the results to particular levels of landfill costs, the total commercial potential for energy-from-waste technology is difficult to estimate. If 50 per cent of the technically feasible projects are assumed to displace heavy fuel oil, the lower bound for commercial potential can be set at one half of the technical potential for MSW energy, or 27.9 PJ per year. If in addition, it is assumed that one half of the projects aimed at the displacement of natural gas involve sufficiently high tipping fees (as specified above), the total commercial potential can be estimated at 41.9 PJ per year. The energy potential is equivalent to the output of some 90 MSW plants of 180 tonnes per day capacity.

4.3.4 Implications for Policy

Energy-from-waste applications in Canada are presently limited to the use of on-site wood wastes in the lumber and pulp and paper industry. The potential for use of municipal solid wastes or off-site wood wastes for steam generation is vastly unexploited. The economic and commercial incentives for development of this potential appear sufficient. However, a number of institutional barriers and market externalities contribute to delay the implementation of projects.

First, the planning and implementation of a steam plant project require the cooperative participation of numerous interested parties, including municipal and regional governments, provincial and federal ministries of energy and environment, equipment suppliers, ratepayer groups and the industrial steam customer. Although all parties may express an interest in EFW, none stands out as a project promoter and investor. Municipal and regional governments have a natural interest in solid waste management, but are frequently hesitant to enter the business of industrial steam production. Even more hesitation is shown by industry which is eager to reduce energy costs but does not wish to enter the business of waste management. Potential owners also face the opposition of local ratepayers who will oppose changes in waste management that are perceived to result in increased traffic, noise and air pollution.

A second barrier pertains to the realization of landfill cost savings. Most municipal and regional governments face landfill costs of $5 per tonne to $10 per tonne. However, the government owner of the EFW plant may not realize all of these savings inasmuch as its costs at an existing landfill site may be fixed, at least in the short run. For example, union contracts may prevent the realization of labour cost savings, or equipment at the landfill site may continue to be needed for auxiliary landfill purposes. There is also a divergence between the private and social costs of traditional landfilling. In measuring landfill cost savings, many municipalities exclude an allowance for the future costs of stricter environmental controls and the future capital costs of required capacity expansion and/or relocation of the landfill site.

Finally, there remains the barrier of risk-averse behaviour from the part of potential steam customers. Given the lack of familiarity with EFW technologies, industry is hesitant to switch from a 'make' to a 'buy' option in meeting its steam requirements. The 'buy' option entails reliance on a government-owned facility that is more complex in its operation than a traditional boiler plant. Consequently a substantial discount may be required as a condition for steam purchase agreements; preliminary studies in Ontario have indicated a price discount of 20 per cent off the energy cost of the 'make' option. As these feasibility studies progress, it is frequently found that the required discount escalates, causing the proposed investment to fall short of commercial viability.

A possible means of overcoming these barriers could be the acceleration of demonstration projects promoted by a multi-partite (federal-provincial-municipal-industrial) organization dedicated to EFW technology and project planning. This group could draw on the staff and experience already embodied in such organizations as the Industry Energy Conservation Task Forces (to promote within industry), renewable energy sections of provincial energy ministries (to promote within municipalities), the federal department of Energy, Mines and Resources and its FIRE program (to encourage innovative incentive packages) and EFW equipment manufacturers (to encourage more promotion by the suppliers themsolves).

Direct financial assistance from federal or provincial governments to municipalities appears necessary in the short-term. The subsidies should allow municipalities to offer more attractive steam prices to industrial customers. The necessary level of subsidies should be expected to decrease over time, as the experience with early projects demonstrates the reliability and financial viability of EFW plants, and as the steam price discounts required by industrial customers gradually diminish.

5. Alternative Transportation Fuels

5.1 Introduction

In 1982, the gasoline share of total energy demand in the road transportation sector in Canada was 88 per cent. The gasoline consumption (1035 PJ) in road vehicles accounted for close to 40 per cent of the total Canadian demand for refined petroleum products.[20] This fraction is steadily increasing as energy substitution in the transportation sector is proceeding at a much slower pace than in the residential, commercial and industrial sectors.

The federal and provincial governments have stressed the importance of developing and commercializing new sources of energy for the transportation sector. Specifically, attention has been given to potential substitutes for gasoline in automobiles and light trucks. The most likely alternatives are propane, CNG and methanol. In addition, the substitution of gasoline for diesel is considered, as a means of achieving greater energy efficiency in automotive vehicles.

This section examines the economic and commercial competitiveness of the above gasoline substitutes. The analysis is carried out on a region-by-region basis and for two classes of vehicles, namely private automobiles and fleet automobiles. The comparative evaluation includes consideration of fuel prices, differential vehicle costs (capital and O&M) and relative fuel efficiencies.

The distinction between private and commercial automobiles is important in view of the differences which exist in the respective levels of energy consumption. For 1995, it is assumed that the average private automobile consumes 1940 litres of gasoline per year (e.g., 20,000 kilometers (km) per year and 9.7 litres per 100 km) and that the fleet vehicle consumes an annual average of 4400 litres of gasoline (e.g., 40,000 km per year and 11.0 litres per 100 km). The private and fleet automobiles are assumed operational for periods of 8 years, and 10 years respectively. As shown below, the above differences in vehicle characteristics amount to contrasting results in the comparative evaluation of the automotive fuels.

5.2 Economic Analysis

Estimating Fuel Shadow Prices

The first step in assessing the economic competitiveness of a transportation fuel is to evaluate the fuel shadow price, that is the cost to produce and deliver the fuel to the private or commercial user. For the present evaluation, the shadow prices of five fuels, namely gasoline, diesel, propane, CNG and methanol, were estimated across ten Canadian provinces. The base case estimates are given in Table 22; the underlying assumptions are briefly reviewed below.

Gasoline is one of the few conventional forms of energy in Canada whose regional market prices systematically exceed actual costs. The gasoline shadow price in each region has been estimated by subtracting from the prevailing pump price the applicable federal and provincial fuel taxes. The estimates given in Table 22 are based on mid-83 prices. The prices were corrected (a) to reflect the assumption of a $215 per cubic meter oil price in Montreal ($325 per cubic meter in the high oil price case), and (b) to attenuate regional differences in retail mark-ups (these are explained in large part by commercial as opposed to economic factors).

Diesel is a joint-product of oil refining but its cost is generally considered to be less than that of gasoline since the product is extracted from a heavier cut of the barrel of oil. Alternatively, diesel can be produced from a lower-cost heavier grade of crude oil than would be required to produce the same amount of gasoline. For both price scenarios, we assume an 85 per cent diesel/gasoline price relationship at the refinery gate. As shown in Table 22, this amounts to a (base case) diesel shadow price advantage over gasoline of some 4 cents per litre.

The shadow prices of propane, CNG and methanol are calculated by estimating the resource costs and by adding a set of mark-ups for distribution and retailing. For propane, the resource cost is given by the liquefied propane export price. The shadow price of CNG is made up of the regional shadow price of natural gas for the commercial sector (itself based on an 85 per cent gas/oil energy price parity at Toronto city gate) and the cost of gas compression and fuelling. Finally, the assumed methanol shadow prices are based on estimates of production and distribution costs available in recent Canadian studies.[21]

Base Case

The shadow prices do not by themselves provide sufficient information for evaluating the cost-competitiveness of the alternative fuels. Other important variables are the fuel energy densities (i.e., the energy content per unit of volume), the thermodynamic efficiency of the respective engines and the differential vehicle costs (capital and O&M). These variables enter the analysis in the calculation of the fuel supply prices. The supply prices are expressed in terms of dollars per unit of gasoline supplied or displaced, and allow for consistent comparisons across the various fuels. It is noted however that the calculation excludes less quantifiable cost factors such as vehicle driving range, or fuel emissions; these factors are not considered in the present analysis.

The base case supply prices, for a 10 per cent real discount rate, are given in Table 23. The results illustrate the clear difference in the economics of conversion between the two classes of vehicles. Supply prices for fleet automobiles are substantially lower as higher volumes of gasoline displacement allow for a better amortization of the initial costs of conversion. In the case of methanol, the effect is less since the capital outlay is minimal.

For private automobiles, gasoline is shown to be the least-cost fuel with supply prices varying from 30 to 34 ¢ per litre. Diesel is the next best alternative. The supply price difference between diesel and gasoline is in the order of 10 per cent, and can be attributed to the incremental cost of the diesel engine; for private automobiles, this cost amounts to some $1800. Propane supply prices fall within a 20 per cent range of gasoline supply prices in all regions. In Alberta, the fuel is nearly competitive with a supply price of 34 cents per litre of displaced gasoline, compared to a gasoline supply price of 32 cents per litre. The results are less favourable for CNG. The fuel is shown to be a relatively expensive option for private vehicles, with supply prices varying from 39 cents (in Alberta) to 47 cents (in Quebec). Methanol provides a similar range of supply prices and therefore, as for CNG, cannot be considered as a cost-effective gasoline substitute for private automobiles, if flat oil prices are assumed.

A different situation prevails in the case of the fleet automobile. Diesel is the least-cost fuel in all regions, with supply prices ranging from 25 to 28 cents per litre of displaced gasoline. This corresponds to a 15 to 20 per cent supply price advantage over gasoline. Diesel is also at least 10 to 20 per cent cheaper, in all regions, than either propane, CNG or methanol. Propane supply prices are roughly equivalent to gasoline supply prices. CNG is also a competitive gasoline substitute in the Western provinces. In Quebec and Ontario however, the fuel is 10 to 20 per cent more expensive than gasoline, and up to 40 per cent more expensive than diesel. Methanol is the most expensive fuel for use in fleet vehicles (as in private vehicles), with supply prices as high as 39 to 45 cents per litre of gasoline displaced.

The analysis suggests that under flat oil prices, gasoline and diesel are the most cost-effective fuels for use in private and fleet automobiles, respectively. The effect of changes in the discount rate on the above result is negligible. However, the impact of variations in energy price assumptions can be significant.

High Oil Price Case[22]

Table 24 lists the set of supply prices corresponding to the high oil price case. The change in the assumed oil price raises the supply price of all five fuels. Higher oil prices imply higher gasoline and diesel costs but also, higher opportunity costs for natural gas and propane and increased production costs for methanol, particularly if produced from natural gas. However, the magnitude of the resulting change in supply price varies across the different fuels and hence, changes in the relative positioning of the competing fuels are observed.

Considering first the private automobile, the increase in oil price is shown to favour diesel vis-à-vis gasoline. In view of the relative efficiency of the diesel engine, the diesel supply price, in each region, falls under the gasoline supply price, at levels of 41 to 44 cents per litre of gasoline equivalent. Propane supply prices fall within the same type of range and hence are also lower than the supply price of gasoline. Interestingly, methanol becomes cheaper than CNG, and remains only 10 to 20 per cent more expensive than diesel. The competitiveness of methanol is improved in the high oil price case because the fraction of energy-related costs in the production and distribution of the fuel is relatively small.

For fleet automobiles, the ranking of the fuels under higher oil prices remains relatively unchanged. In particular, the positioning of diesel as the least-cost fuel is confirmed. Diesel supply prices range from 32 to 35 cents per litre of displaced gasoline wheareas the supply prices of all other fuels, including gasoline, generally exceed the 40 cents per litre level. The supply price advantage of diesel over gasoline is in the order of 30 per cent, which compares to a base case diesel advantage of some 15 to 20 per cent. Propane and CNG are cheaper than gasoline, but at least 10 per cent more expensive than diesel, in all regions. Finally, methanol supply prices, as in the base case, are found to be the highest at levels of 46 to 53 cents per litre of gasoline displaced.

General Comment

The supply price advantage of oil-based fuels in both oil price cases is noteworthy. Changes in the price of oil affect the relative cost-effectiveness of gasoline and diesel (higher oil prices favour diesel), but do little to improve the potential for use of propane, CNG or methanol in either private or fleet vehicles. The result is sensitive to a number of factors. With regards to CNG for example, the dominant question is that of the natural gas shadow price.

The CNG supply prices given in Tables 23 and 24 are based on the assumption of an 85 per cent natural gas/oil energy price parity at the Toronto city gate, for 1995. The 85 per cent parity ratio figures among a wide range of values which can be used to approximate the 1995 gas shadow price. If gas export markets remain saturated as they are at present, and if Canadian gas supply surpluses prevail into the 1990s, the actual ratio for 1995 could be considerably lower. This, in turn, would improve the competitiveness of CNG as a gasoline substitute for the 1990s.

To examine this possibility, supply price calculations for CNG were performed using a 60 per cent gas/oil energy price parity. For the base case, the use of the lower ratio results in a net reduction in CNG supply prices of some 5 to 6 cents per litre of gasoline equivalent. If the high oil price is assumed, the CNG supply prices are reduced by as much as 8 cents per litre of gasoline equivalent. It can be verified in Tables 23 and 24 that under such conditions, CNG could be economically viable in the Prairie provinces, for use in fleet automobiles. The result provides an indication of the competitiveness of CNG under the current situation of low gas shadow prices in Canada.

Other assumptions could be revised to reevaluate the supply prices of diesel, propane or methanol. The relative cost-effectiveness of the competing automotive fuels is therefore difficult to assess in a clear-cut manner. However, the positioning of diesel as the best gasoline substitute for 1995 prevails under a fairly wide range of assumptions. As shown below, the result does not extend to the commercial analysis where, in view of tax considerations, the market potential for diesel appears more limited.

5.3 Commercial Analysis

The commercial analysis of alternative fuels is limited to the diesel, propane and CNG options. Investments are considered for fleet vehicles only as these represent the most likely market for alternative fuels in the medium term.

The investment decision-maker is the fleet owner. The financial feasibility of the investments in alternative fuels is measured by simple payback and return on equity, calculated on a 5 year cash flow basis. Private (as opposed to government) ownership is assumed and therefore, fuel savings and capital grants are taxed at the corporate rate of income tax. Vehicle purchases and/or conversions are assumed financed by 100 per cent equity, and are written-off on the basis of a 30 per cent declining balance capital cost allowance.

The available capital grants include federal propane and CNG grants of $400 and $500 (1983$), respectively. CNG conversion costs in Quebec and British Columbia are reduced by taxable grants from the Montreal gas utility ($500, 1983$) and the B.C. government ($200, 1983$), respectively. In Ontario, an implicit subsidy is allowed through the exemption of sales tax on propane, or CNG equipped vehicles.

Current market prices were collected, or estimated for gasoline, diesel, propane and CNG, and are given in Table 22. These prices are assumed to remain constant in real terms to, and beyond 1995.

Table 25 summarizes the results of the financial evaluation. The ranking of the fuels in terms of the relative profitability of the investments is shown to differ substantially from that observed in the economic analysis.

From the point of view of the fleet owner, CNG is the most profitable alternative to gasoline in most regions. Investments in CNG conversions are paid back in 1 to 3 years, and earn nominal rates of return on equity in excess of 30 per cent. The high investment returns stem from favourable market conditions: natural gas prices are low, fuel taxes on CNG are zero and conversion grants cover an important fraction of the initial investment. In Quebec (Montreal) for example where a total $1000 subsidy can be received for converting to CNG (and where gasoline taxes are highest), the investor can be paid back in slightly more than 1 year and profit from a 60 per cent rate of return on equity.

Similar conditions provide extremely good financial benefits for propane conversions in Ontario. Federal and provincial subsidies amount to the full investment cost, and the fleet owner can collect annual cost savings of some $400 per vehicle. In other provinces, propane marketing policies are less aggressive and as a result, propane cannot adequately compete with CNG.

The commercial potential for diesel is marginal. Based on current price and tax regimes, diesel is only the second, or third most likely choice for investment. Paybacks range from 3 to 4 years, and the nominal rates of return on equity fall under the

20 per cent level. A determining factor for the competitiveness of diesel vis-à-vis gasoline is the price differential between the two fuels. In several provinces, the differential is either negligible, or at the advantage of gasoline. Most provinces apply heavier taxes per unit of volume on the more efficient diesel fuel in order to collect the "appropriate" road user fee.

The above results show that the relative positioning of the alternative fuels in the transportation market is much more a question of taxes and subsidies than a question of economic costs. To a large extent, governments hold the key to the development of future markets for alternative fuels. The identification and promotion by governments of the most promising options is therefore a very important step towards realizing least-cost energy solutions in the transportation sector.

5.4 Implications for Policy

The area of alternative transportation fuels is one in which the federal and provincial governments have already taken a number of actions. Through incentives in the form of conversion grants or fuel tax exemptions, governments are actively promoting the conversion of vehicles to propane and CNG. As shown in our commercial analysis, the measures allow fleet owners to realize attractive rates of return on vehicle conversion investments. Markets are expected to develop rapidly with the implementation of proper supply networks for the respective fuels. As an example, it is expected that 100,000 vehicles (mainly in Ontario) will have converted to propane by 1985.[23]

It is clear that policies directed at the commercialization of propane and CNG contribute to reduce gasoline consumption. It is less clear whether or not these policies are contributing to reduce long-term energy costs. Our calculations indicate that for 1995, propane and CNG may be relatively expensive for use as automotive fuels. This result contrasts with those of other fuel cost comparisons published by government agencies or private promoters of propane and CNG. The differences arise because a number of studies confuse the concepts of economic and commercial feasibility. For example, the price of tax-exempt alternative fuels is frequently compared to the tax inclusive pump price of gasoline; net energy cost savings are thus overstated.

Our analysis identifies diesel as the most promising gasoline substitute. Rough calculations indicate that by 1995, diesel could replace gasoline in up to 300,000 new fleet vehicles per year and provide savings of 10 to 30 per cent in terms of energy costs and 35 per cent in terms of oil volume. Under higher oil prices, diesel could also substitute for gasoline in a fraction of new private automobiles. The potential for substitution is subject to the capacity of Canadian oil refineries to adjust to changes in the composition of oil product demand over time.

The potential for diesel cannot be realized under the present set of market conditions. Discriminatory fuel taxes, and lack of government support place the fuel at a market disadvantage not only vis-à-vis gasoline, but vis-à-vis propane and/or CNG in a number of provinces. Adjustments appear necessary to establish a more cost-oriented balance in the transportation fuels market. Provinces should revise fuel taxing policies to allow diesel to become more competitive. Federal programs in the area of transportation fuels should also be reevaluated, particularly if it is confirmed that these programs are limiting the penetration potential of the most cost-effective gasoline substitute.

But considerations other than relative fuel costs should enter the evaluation of medium to long-term energy strategies for the Canadian transportation sector. A first consideration is security of supply. It can be argued that the promotion of diesel as the preferred gasoline substitute can only contribute to the perpetuation of oil-dependence in the Canadian transportation sector, and that on the other hand, the development of markets for propane and CNG can reduce this dependence, and thus improve the degree of resilience of the Canadian economy in the event of oil supply interruptions. We accept this argument but it is important to assess the full cost of an increased penetration of propane and/or CNG (i.e., the energy cost penalty), and to compare this cost to the cost of implementing other oil supply safeguards such as intensified energy conservation, or crude oil stockpiling. Such an analysis, obviously, falls beyond the scope of the present paper.

The potential for diesel, propane and CNG should also be assessed in terms of the capacity of the transportation sector to accomodate more than two or three different fuels. For example, if gasoline and diesel are, as our analysis suggests, the most cost-effective transportation fuels, there is question as to the economic viability of more than one or two additional alternatives. The promotion of too many alternatives by government could in effect result in system inefficiencies, and additional costs.

Finally, it is important that fuel options which are not necessarily competitive in the short to medium term be evaluated in terms of their long-run potential to provide low-cost energy. From this point of view, propane is probably at a comparative disadvantage. In 1981 the National Energy Board had projected that propane could be in short supply in Canada by as early as 1990.[24] Recent revisions of the forecast show that surpluses could exist for a longer period, but that they would still be gradually decreasing.[25] The long-term potential for the cost-effective use of propane in Canadian vehicles may therefore be limited. In terms of future supplies, CNG and methanol offer greater potential. It is not unlikely that within a period of 20 to 30 years, the two fuels could become the preferred options for fleet and private vehicles, respectively. It is perhaps more important to concentrate on these long-term opportunities than to create artificial short-term markets for either propane or CNG. Funds presently allocated to the commercialization of propane and CNG, for example, could perhaps be better utilized in research programs aimed at reducing the production costs of methanol from different sources (natural gas, coal and wood), or at reducing methanol and/or CNG user costs.

In summary, the analysis suggests that diesel should be the preferred gasoline substitute in commercial vehicles in the short to medium term. Research, development and demonstration programs should also be supported to assist the development of long-term markets for CNG and methanol. Less attention and program resources should be devoted to propane.

6. Site-Specific Renewable Energy

6.1 Small Hydro

6.1.1 Introduction

"Small hydro" typically refers to hydroelectric projects with generating capacities below 25 to 50 megawatts (MW). It is estimated that the nationwide technical potential for such projects amounts to some 9000 MW of power, or roughly 10 per cent of the total installed generating capacity in Canada.[26] Likely applications of small hydro technology are (a) for the self-generation of hydro power by institutions adjacent to the sites and currently served by electricity grids and, (b) for the displacement of diesel fuel for off-grid electricity generation in remote communities.

Our analysis of small hydro is based on case studies developed for the Ontario Ministry of Energy.[27] Three projects are considered, with respective small hydro capacities of 2.8 MW, 2.0 MW and 0.7 MW. The projects are assumed to supply an adjacent industrial user and hence transmission and distribution costs are not included in the evaluation. The economic and commercial viability of the projects is assessed across the ten provinces, based on the costs and prices of electricity for the industrial sector, as given in Table 9. A 50 year useful life is assumed.

6.1.2 Economic Analysis

Base Case

As shown in Table 26, the supply prices for the three projects for a 10 per cent real discount rate are estimated at 2.0 cents per kilowatt-hour (kWh) 3.0 cents per kWh and 9.0 cents per kWh, respectively. The supply prices increase as the generating capacity decreases, reflecting a returns-to-scale effect on project costs. The two larger projects can be shown economically viable by comparing their respective supply prices to the regional shadow prices of electricity, as given in Table 9; these range from 3.3 cents per kWh in Ontario to up to 10 cents per kWh in the Maritimes. The third and smallest project is economically viable in the Maritime provinces, only.

In view of the site-specific nature of small hydro projects, the results of the supply price analysis do not provide sufficient information for the assessment of the economic potential for small hydro (e.g., in MW of power). Discussions with utility officials suggest that the potential may in effect be limited, particularly if transmission and distribution costs are incurred to connect small hydro sites to potential customers. Hence, a small fraction of the technical capacity could be assumed economically implementable.

Base Case, Lower Discount Rate

Small hydro supply prices are quite sensitive to variations in the social discount rate. If a 7 per cent rather than 10 per cent real discount rate is used, the supply prices decrease by a factor of some 25 per cent. However, since the change in discount rate results in similar decreases in the cost of electricity generated from conventional means, the competitiveness of small hydro projects remains unchanged.

High Oil Price Case

In order to estimate the effect of an increase in the price of oil on the competitiveness of small hydro, it would be necessary to measure the relative impact of the increase on the costs of small hydro, and conventional electricity generation. We have not carried out this exercice. Presumably, the analysis would show that small hydro becomes more competitive vis-à-vis diesel or other forms of thermal generation, but not necessarily vis-à-vis hydro or nuclear generation.

6.1.3 Commercial Analysis

The evaluation of commercial feasibility assumes government ownership of small hydro projects. The electricity output is sold to an industrial user at a price equal to the regional price of electricity for the industrial sector, as given in Table 9. The investment debt equity ratio is 9-1, the debt carries a real annual cost of 4 per cent and is repaid over a period of 20 years.

The financial analysis of the three projects is summarized in Table 26. As expected, the projects show the highest and lowest rates of return in provinces with the highest and lowest market prices of electricity, respectively. The largest small hydro project provides paybacks of less than 8 years, and nominal rates of return on equity (ROE) of at least 20 per cent in all provinces. The results are less conclusive for the second project. The ROE exceeds 15 per cent in all provinces, but the payback is greater than 10 years in Manitoba (20), Alberta and British Columbia (15) and Quebec (11); this contrasts the result observed in the economic analysis which indicates interesting cost savings in all provinces for this project. The third project is not commercially feasible; ROEs fall below 10 per cent and paybacks exceed 25 years in all provinces.

Sufficient financial incentives therefore appear to exist for the development of low-cost small hydro projects. However, a sizeable fraction of projects may fail to meet public or private investment criteria in view of either low electricity prices (e.g., low project revenues) or excessive project costs.

6.1.4 Implications for Policy

The economic parameters for small-hydro projects are highly site-specific. The potential capacity of the projects, and the proximity and demand profile of the customers are important variables. Our calculations suggest that projects supplying 2 megawatts or more of power to adjacent customers can be economically viable, at selected sites. However, relatively few such projects have been implemented in recent years. Barriers to small hydro development include electricity pricing policies, and other institutional factors.

The question of electricity pricing has been discussed in the section on electricity cogeneration. The present low electricity prices reduce, or altogether eliminate the incentive for public and/or private investors to become involved in small-scale generation. While some projects may be competitive under present prices, the potential for small hydro, and for other electricity generation or conservation technologies, will be fully realized only to the extent that electricity prices eventually reflect the higher long-run marginal costs.

Small hydro is essentially a matter of provincial responsibility; the participation of the federal government is generally limited to remote community off-oil projects. But difficulties arise from the absence of interest groups prepared to actively promote the technology. Provincial ministries dealing with renewable energies do not have operational responsibility to develop small hydro sites. Although small project departments exist within most electrical utilities, emphasis is obviously placed on conventional means of electricity generation (hundreds of small hydro projects are required to produce the output equivalent of a large hydro or nuclear complex). Small hydro investment opportunities may therefore be left unexploited.

Policies to encourage the more rapid development of small hydro could be developed by the provinces and the provincial utilities, with operating responsibilities delineated within the utilities. The industrial development and ownership of small hydro projects could also be promoted and, as in the case of cogeneration, utilities should be encouraged to provide favourable terms for the purchase of excess power and energy from industrial generators. At the federal level, the current programs, including accelerated write-offs on equipment, and support for Arctic and other remote community off-oil small hydro projects, should be continued.

6.2 Geothermal Energy

6.2.1 Introduction

Geothermal energy denotes the heat energy emitted from within the crust of the earth in the form of hot water or steam. The resource is unevenly distributed across the different geological regions in terms of both the quantity and quality of energy. Hence, the potential applications for geothermal energy are site-specific. Dry steam fields such as these found in California can supply steam at temperatures of 150°C to 300°C to electricity generating steam turbines, while hot water and hot brine fields, containing water at some 60°C to 100°C, may be used for low temperature applications such as space and water heating and low-grade industrial process heating.

In Canada, geothermal energy resources are generally of the low-temperature type and are concentrated in the four Western provinces. Canadian information on the resource, and the design and cost of supply systems is limited. The analysis in this section relies on four case studies developed for the National Research Council.[28]

Four applications of geothermal energy are considered: residential space and water heating; commercial space and water heating; greenhouse heating; and mine ventilation air heating. The projects are evaluated for economic and commercial feasibility across the four Western provinces. In all cases, natural gas is assumed displaced; the regional shadow prices and market prices of natural gas for the relevant end-use sectors (residential, commercial and industrial) are given in Tables 27 and 28. A 20 year investment horizon is assumed.

6.2.2 Economic Analysis

The costs of geothermal energy vary across the different types of application. Varying temperature requirements dictate different well depths, and economies of scale materialize as energy demands become larger, and less dispersed. The cost differences are reflected in the supply prices of the four sample projects, as shown in Table 27. The supply prices are expressed in cents per cubic meter (m^3) of gas displaced.

The residential space and water heating project is the most expensive. Its supply price, 42 cents per m^3, is twice as high as the shadow price of residential natural gas in the Western provinces. The space and water heating application is more cost-effective in the commercial sector. The estimated supply price is 16 cents per m^3 whereas regional gas shadow prices for the commercial sector range from 16 to 20 cents per m^3. The greenhouse heating and mine ventilation air heating projects are distinctly competitive. The supply prices are estimated at 13 cents per m^3 and 12 cents per m^3, respectively; these values are 15 to 35 per cent lower than the corresponding gas shadow prices in the Western provinces.

As in the case of small hydro, the economic potential for geothermal energy, in terms of aggregate supply, is not estimated. This potential is limited not only by the resource availability factor but also, by the number of potential applications and customers. The base case analysis identifies some possibilities for applications such as greenhouse heating and mine ventilation air heating but the prospects appear to be less favourable for the more common and widespread energy end-uses such as building space heating.

Lower Discount Rate/High Oil Price Case

The cost-competitiveness of geothermal energy projects increases if a lower discount rate, or higher gas prices are assumed. The use of a 7 per cent rather than 10 per cent real discount rate reduces the supply prices of the projects by 10 to 15 per cent. In the high oil price case, gas shadow prices increase by some 9 cents per m^3 and hence the relative cost-effectiveness of geothermal energy investments is considerably improved. In all cases however, the residential energy project remains expensive.

6.2.3 Commercial Analysis

The financial evaluation of the four geothermal energy projects assumes government ownership. The debt-equity ratio of the investment is 9-1, with a 4 per cent real annual cost of capital. The investment horizon and debt repayment period are assumed equal to the service life of the project, i.e., 20 years. Using the regional market prices of natural gas, payback and nominal rates of return on equity (ROE) were determined for each of the four projects, as shown in Table 28.

The residential space and water heating project is not commercially viable; in all four provinces, the project payback is greater than 20 years. The commercial space and water heating application is marginally profitable in Manitoba and British Columbia where paybacks are less than 10 years and ROEs are greater than 20 per cent. As in the economic analysis, greenhouse heating and mine ventilation air heating are shown to be the most promising applications for geothermal energy. In Manitoba and British Columbia, the projects are paid back in less than five years, and ROEs exceed 30 per cent. In Saskatchewan, where gas prices are lower, paybacks are in the order of 10 years and ROEs are slightly above the 15 per cent level. In Alberta, none of the four geothermal energy projects are commercially feasible.

As observed in the economic analysis, the investment opportunities for geothermal energy projects appear limited to energy end-uses for which demands are relatively small. The development of the geothermal energy potential can thus be expected to proceed slowly.

6.2.4 Implications for Policy

Unlike small hydro, low-temperature geothermal energy projects have not yet been demonstrated and tested. Even the resource base estimates are subject to greater variations than in the case of small hydro. Given current cost estimates, the utilization of geothermal energy is economically and commercially feasible only in limited applications such as greenhouse and mine ventilation air heating. Space and water heating in commercial buildings is a borderline application in terms of economic and commercial feasibility.

Policies in the area of geothermal energy should continue to be directed at the development of demonstration projects. The research, development and demonstration (RD&D) program should have the objective of estimating the resource base and reducing capital costs to achieve broader economic potential in the Western provinces. A potentially valuable by-product of such RD&D would be the technical expertise that could be exported to Third World countries (e.g., East Africa) that have significant proven geothermal resources and that are receiving bilateral/multilateral aid to exploit these resources.[29]

6.3 Wind Energy

6.3.1 Introduction

Wind energy is a resource which has been known and exploited for centuries. The energy price escalations of the 1970s have kindled interest in different applications of the related technology. In particular, wind electricity generation has been given considerable attention. Wind turbine generators have been implemented at selected sites in Canada and abroad either as part of the electricity supply grid, or as add-ons to diesel generating units in remote communities.

The potential areas for wind energy exploitation in Canada are limited. The sites are concentrated about the coast of Hudson's Bay, the northern edge of Quebec and Labrador, the Atlantic Coast and the St-Lawrence Gulf.

The case study reviewed in this section concerns a joint Hydro-Quebec/National Research Council project for the implementation of 6 wind turbine generators of 500 kilowatts capacities in the Magdalen Islands (Quebec), a site known to offer particularly favourable wind regimes.[30] The project is assumed to to displace diesel fuel used for conventional electricity generation. The costs of the turbine (capital and operating and maintenance) are measured against the value of the fuel savings realized over the 20 year project life. The analysis does not take into account questions of capacity planning (e.g., capacity credits), which generally enter the evaluation of grid-connected wind turbines that delay the implementation of other, conventional types of generating units.

It is noted that the results discussed below are specific to the Magdalen Islands site. The most important site-specific variable is the annual volume of diesel fuel displacement. For the Magdalen Islands, a value of 1900 cubic meters per year is assumed (for the 6 turbines combined). Potential fuel savings at other Canadian locations could be less.

6.3.2 Economic Analysis

Base Case

The project supply price, for a 10 per cent discount rate, is estimated at $380 per cubic meter of diesel fuel displaced. The supply price can be compared to the shadow prices of diesel fuel. For the Magdalen Islands, the base case diesel shadow price is in the order of $275 per cubic meter and hence the wind energy project appears relatively expensive.[31] In northern communities, diesel costs are generally higher and can reach levels of $800 per cubic meter.[32] Where wind regimes are favourable, interesting prospects for wind energy can be identified in such communities.

Base Case, Lower Discount Rate

The project is shown more economically attractive by assuming a 7 per cent rather than 10 per cent real discount rate. The change in discount rate results in a 15 per cent supply price reduction, from $380 to $320 per cubic meter of diesel fuel displaced. For the Magdalen Islands, the project remains expensive at this level of supply price.

High Oil Price Case

Under the scenario of high oil prices, the shadow price of diesel fuel is assumed to increase by some $110 per cubic meter in all regions. The increase is just sufficient to ensure the economic viability of the wind energy project in the Magdalen Islands.

The above results show that in specific locations, and under specific conditions, wind energy projects can be economically viable. The total economic potential for such projects however is limited. Apart from economic considerations, geographical limitations and the intermittant nature of the resource are among the main barriers. In terms of remote community applications, an absolute upper bound on the potential is given by the total capacity of diesel generating units in Canada. This capacity is in the order of 350 megawatts,[33] dispersed in approximately the same number of communities. Wind energy systems could be assumed economically feasible in only a fraction of these communities. With regards to the connection of wind generating turbines to provincial supply grids, the technical potential is sizeable but the economic potential is generally considered as very limited as wind energy systems remain expensive compared to conventional alternatives such as hydro, nuclear or thermal power systems.

6.3.3 Commercial Analysis

The assumptions used in the commercial analysis of the wind energy project are analogous to those used in the evaluation of other site-specific energies. Government or utility ownership is assumed. Debt to equity ratio is 9 to 1 and the debt carries a real annual cost of 4 per cent per year. The loan repayment period is 20 years, and is therefore equal to the assumed turbine service life. Diesel fuel savings are valued at a range of constant real prices. A range of $250 per cubic meter to $400 per cubic meter is sufficient to indicate levels at which the project falls in the "go", or "no-go" category.

The calculated paybacks and nominal rates of return on equity (ROE) are given in Table 29. The results indicate that if diesel prices are at, or above, a level of $300 per cubic meter, the wind energy project can be cost-effective from the public investor's viewpoint, i.e., the payback is less than 10 years and the ROE is greater than 15 per cent. The result is somewhat surprising since economic feasibility for the same project is achieved, under base case assumptions, only if diesel shadow prices exceed $380 per cubic meter. In contrast to the situation which prevails in most energy markets, a bias exists in favour of the renewable energy alternative. The bias is due to the low cost of capital used in public or utility owned projects. The public investor discounts future fuel savings at a real rate of 4 per cent per year whereas social discount rates of 7 to 10 per cent per year are used in the economic analysis. The total value of fuel savings over the life of the project is thus greater in the commercial evaluation, and the cost-competitiveness of the project is shown improved.

The market prices for diesel in remote communities vary from \$260 per cubic meter to more than \$800 per cubic meter.[34] In the Magdalen Islands, the price is in the order of \$250 per cubic meter and hence the wind energy project is not commercially feasible and has not, as a matter of fact, gone ahead.[35] In selected remote communities however, the project could generate substantial savings. As shown in Table 29, ROEs can be as high as 46 per cent in regions where diesel prices reach \$400 per cubic meter.

6.3.4 Implications for Policy

Wind energy has been shown to offer attractive investment opportunities in selected, remote regions. Assuming government or utility ownership, economically feasible projects can be shown commercially implementable without any form of external subsidy.

The policies aimed at the development of wind energy technology are, as in the case of small hydro, largely in the domain of the utilities. Studies and research should continue, at establishing the resource base with increasing accuracy and at encouraging the manufacture of lower-cost and more reliable hardware by those Canadian firms already active in this sector. As with geothermal energy, the export potential of such expertise and equipment is significant. Aid agencies such as the World Bank have expressed interest in wind energy in the context of their energy assessment reports on developing countries.

7. Conclusions

This paper has evaluated the economic and commercial competitiveness of a selection of energy conservation and alternative energy technologies. It has identified a number of cost-effective investments for the displacement of conventional forms of energy in different regions and end-use sectors in Canada. The discussion has also suggested that for a variety of reasons markets may fail to encompass such opportunities and that unnecessary delays can occur in the adoption of economically efficient energy solutions. Different policy initiatives have been proposed to alleviate these difficulties and to stimulate the economic development of the most promising technologies.

The proposed policies can be grouped under three broad policy objectives. These, respectively, concern questions of pricing, information and incentives.

The first objective is to ensure that the market prices of energy reflect the true opportunity costs of the respective resources. This, historically, has not been the case in Canada. The domestic price of oil, since 1973, has been held below the opportunity cost defined by the world price. Natural gas prices have been arbitrarily tied to the price of oil, and the costs of gas distribution have not been fully reflected in the regional market prices of the fuel as a result of implicit and explicit government subsidies. Electricity prices have been separately administered in each province, and have often been out of step with the true opportunity cost of the resources used in electricity generation, transmission and distribution. These, and other price distortions have unduly reduced the incentives for Canadians to implement alternatives to conventional energy supplies. Policy adjustments appear necessary at both the federal and provincial levels to provide more adequate price signals to the markets. The revision of energy pricing is identified as the single most important step towards promoting the economically efficient introduction of new energy technologies.

The question of pricing introduces the broader question of market information. Markets can be expected to function properly only to the extent that sufficient and adequate information is available for the evaluation of competing investments. Apart from appropriate price signals, energy markets require information on the characteristics and costs of the available resources and technologies. Policies directed at the development of alternative energy technologies should therefore aim at accelerating the dissemination of relevant information within the market place. This can be achieved through such means as the publication of research material and case studies, the sponsoring of seminars and conferences and the supply of direct assistance to decision-makers. Positive steps have been taken in this direction in recent years. Public and private investors have become better informed, and less cautious with regards to emerging energy technologies. Continued efforts are necessary however to improve the availability and reliability of information and to direct markets towards the most effective energy solutions.

Considerable progress can be achieved in the development of conservation alternative energy technologies by relying on the market forces. But markets remain imperfect. Institutional factors and market externalities can create biases towards conventional energy solutions, causing investors to apply unreasonable financial criteria to energy conservation or alternative energy investments. Finally, the different short-term fluctuations in the costs of energy can fail to reflect long-term trends and can create confusion within the energy end-use markets with regards to the competitiveness of different energy investments.

To the extent that such factors curtail the development of promising energy technologies, governments may find it necessary to introduce different types of incentives. Depending on the stage of development of the technologies, the incentives can take the form of R&D grants, equity investments in demonstration projects, direct subsidies, tax write-offs and/or capital fund lending. Such assistance needs to be selective, and directed at only those technologies which, in selected regions, demonstrate an economic potential but fail to achieve an adequate level of development and/or market penetration. The incentives should also be devised so as to adapt to changing market conditions, including prices. In particular, any financial subsidies and incentives should be designed to decrease as markets become better informed.

Most of the technologies examined in this report have been shown to demonstrate a potential for providing low cost energy for Canadians. More opportunities exist, in all sectors, to improve the efficiency of energy production and use. Altogether, energy conservation and alternative energies can make a significant contribution towards satisfying Canadian energy needs. Insofar as market prices are properly set and adequate information is made available, markets can be expected to respond to these opportunities. But as shown in this report, active government involvement may be required, in selected cases, to cope with institutional barriers or market externalities, and to help achieve the full economic potential of the respective technologies.

Notes

1 Comparisons of aggregate and sector-specific indicators of energy-efficiency are found, among other sources, in Slagorsky, Charles Z., Energy Use in Canada in Comparison with Other Countries, Canadian Energy Research Institute, Study No. 8, Calgary, 1979; and Cain, Bobbi, "International Energy Comparisons, A View of Eight Industrialized Countries", Discussion Paper No. 222, Economic Council of Canada, Ottawa, 1983.

2 Several researchers argue that we should go beyond the economic limit, that there is an ethical/social value attached to the conservation of our resources. Such arguments have merit. However, we have chosen in this paper to focus our analysis on the criterion of economic efficiency. For further reading, we recommend Brooks, D.B., Zero Energy Growth for Canada, McLelland and Stewart, Toronto, 1981; and Lovins, Amory B., Soft Energy Paths - Towards a Durable Peace, Harper and Row, New York, 1979.

3 Among the most recent and comprehensive contributions, we note the following: Task Force and Energy Conservation Technologies, Energy Conservation Technologies and Their Implementation, A Report to the Minister of State for Science and Technology, Supply and Services Canada, Ottawa, 1982; and the Special Committee on Alternative Energy and Oil Substitution, Energy Alternatives, Supply and Services Canada, Ottawa, 1981.

4 Let I_t be the capital investment in year t, C_t the project cost in year t (energy and O&M), Qt the energy output (or savings) in year t, T the project life and r the discount rate, then the supply price SP is such that

$$\sum_{t=0}^{T} \frac{SP \cdot Q_t}{(1 + r)^t} = \sum_{t=0}^{T} \frac{I_t + C_t}{(1 + r)^t} ,$$

and hence

$$SP = \sum_{t=0}^{T} \frac{I_t + C_t}{(1 + r)^t} \div \sum_{t=0}^{T} \frac{Q_t}{(1 + r)^t} .$$

The project supply price SP is compared to the supply price SP' of the displaced energy commodity, given by

$$SP' = \sum_{t=0}^{T} \frac{P_t \cdot Q_t}{(1 + r)^t} \div \sum_{t=0}^{T} \frac{Q_t}{(1 + r)^t} ,$$

where P_t is the shadow price or opportunity cost of the displaced energy commodity in year t. For the calculations presented in this paper, P_t and Q_t are assumed constant and hence

$$SP' = P_0 .$$

The calculated supply prices for alternative energy technologies are therefore compared to the shadow price at t=0 (1995) of the corresponding displaced energy commodities.

5 An exception is made in Section 3 where "private" supply prices are used for the evaluation of commercial feasibility.

6 Energy, Mines and Resources Canada, Energy Statistics Handbook, Ottawa, 1984.

7 For example, our estimated Alberta border shadow price in the base case is $4.00 per gigajoule (GJ), compared to a mid-83 domestic price of $2.06 per GJ at the border, and a (firm) export price of $4.35 per GJ (prices in 1981 $ Can.). Domestic and export prices quoted from Energy, Mines and Resources Canada, op. cit.

8 Residential fuel shadow prices for the high oil price case are obtained by taking the shadow prices of Table 1, by adding premiums of 11 cents per litre, and 9 cents per cubic meter to the shadow prices of oil and gas, respectively; and by increasing electricity and wood shadow prices by 15 per cent in all regions. The shadow prices are assumed constant in real terms throughout the post-1995 investment horizon.

9 See Acres Shawinigan Ltd., Study of the Potential for Cogeneration in Canada, Industrial Steam Turbines, Volume 1 - Main Report, Energy, Mines and Resources Canada, Industry Series, Publication No. 1, December 1979, and Acres Consulting Services Ltd., An Economic Update of the Potential for Cogeneration in Canada, Industrial Steam Turbines, Energy, Mines and Resources Canada, Industry Series, Publication No. 1a, August 1982.

10 Industrial fuel shadow prices for the high oil price case are obtained by taking the shadow prices in Table 9, by adding premiums of 11 cents per litre and 9 cents per cubic meter to the shadow prices of oil and gas, respectively; and by increasing electricity and wood shadow prices by 15 per cent in all regions. The shadow prices are assumed constant throughout the post-1995 investment horizon.

11 See Lalonde, Girouard, Letendre and Associates Ltd., Energy Cascading Potential in Canadian Industry, Data Base for 1978, Industry Series Publication 31, Energy, Mines and Resources Canada, December 1981.

12 Ibid.

13 The technical recovery factor determined in the Lalonde, Girouard, Letendre (LGL) study, op. cit., was applied to the 1982 energy demand figures for manufacturing and mining, from Statistics Canada, catalogue 57-003, 1982-IV. As indicated in the LGL study, the total potential for waste heat recovery may in effect be considerably larger because of the significant quantities of non-purchased energy used in industry, and not compiled by Statistics Canada.

14 The data were taken from the following studies: General Motors Corporation, "Industrial Energy Conservation - 101 Ideas at Work", Energy Management Section, General Motors Corporation, Detroit, 1977; Diener, S.G. and R.B. James, "A Comparison of the Costs of Energy Conservation and Energy Supply in Canada", (edited and condensed from a report prepared by Acres Consulting Services Limited), Energy, Mines and Resources Canada, May 1981; and James, R. B., "Saving Energy and Money Through Energy Use Management - The Mining and Metallurgy Experience", mimeo, presented at CIM Annual General Meeting, Quebec City, April 1982.

15 To convert gas prices in dollars per cubic meter (as given in Table 9) to dollars per gigajoule, multiply by 26.88. The conversion of heavy fuel oil prices in dollars per litre to dollars per gigajoule is performed by multiplying by a factor of 24.

16 See Diener and James (1981), op. cit.

17 The data for the evaluations are from Acres Consulting Services Ltd., Energy From Waste in North Bay, study prepared for the Ontario Ministry of Energy, the Ontario Ministry of the Environment and the Nordfibre Company, Toronto 1979, also, Diener and Smith (1981), "The Comparative Resource Costs of Energy from Waste", (Mimeo), presentation to the Third Annual IAEE Conference on International Energy Issues, University of Toronto, Toronto, 1981.

18 Statistics Canada, 57-003, 1982-IV.

19 Industrial fuel shadow prices for the high oil price case are obtained by taking the shadow prices in Table 9, by adding premiums of 11 cents per litre and 9 cents per cubic meter to the shadow prices of oil and gas, respectively; and by increasing electricity and wood shadow prices by 15 per cent in all regions. The shadow prices are assumed constant throughout the post-1995 investment horizon.

20 Statistics Canada, 57-003, 1982-IV; the shares of energy demand in road transportation are as follows: gasoline 87.8 per cent, diesel 11.7 per cent, liquid petroleum gases 0.3 per cent, and electricity 0.2 per cent.

21 See for example Slagorsky, C., Alternative Transportation Fuels in Canada, Study No. 16, Canadian Energy Research Institute, The University of Calgary Press, July 1982; and PPS Ltd., Alternative Fuels Production Costs, report presented to the Transportation Energy Division, Energy, Mines and Resources Canada, Ottawa, 1983.

22 The world oil price in the high oil price case is 50 per cent higher than in the base case; the absolute increase in terms of 1981 $ is in the order of $110 per cubic meter. The fuel shadow prices are revised according to the following assumptions:

- The gasoline shadow prices increase by 13 cents per litre, and diesel shadow prices increase by 11 cents per litre; the differential increase is such that the assumed 85 per cent diesel/gasoline price relationship (at the refinery gate) is maintained.
- The propane export price increases by 50 per cent, or 5.4 cents per litre; the increase is directly applied to the regional fuel shadow prices.
- The increase in CNG shadow prices is defined by the increase in the imputed gas shadow price at Toronto city gate, and amounts to some 9 cents per cubic meter.
- Methanol production costs increase by some 4 cents per litre.

23 See Energy, Mines and Resources Canada, National Energy Program Update 82, Supply and Services Canada, Ottawa, 1982.

24 See National Energy Board Canada, Canadian Energy Supply and Demand 1980-2000, Supply and Services Canada, Ottawa, 1981.

25 Unpublished forecasts obtained from the Oil and Alternative Energy Supply Group of the National Energy Board.

26 See Lanmer Consultants (1978) Ltd., Considerations for Small Hydro Development in Off-Grid Remote Locations, report prepared for Energy, Mines and Resources Canada, July 1982 (pre-publication copy).

27 See Acres Consulting Services Limited, An Analysis of Constraints to Small Hydro Development in Ontario, report prepared for the Ontario Ministry of Energy, Toronto, September 1982.

28 See Acres Consulting Services Limited, A Study of Low-Temperature Geothermal Applications, prepared for the National Research Council of Canada, Vancouver, 1983.

29 See for example World Bank, The Energy Transition in Developing Countries, World Bank, Washington, 1983; World Bank, The Joint UNDP/World Bank Energy Sector Assessment Program and Energy Sector Management Program, A Progress Report, World Bank, Washington, November 1982; see also the country-specific energy assessments published by the World Bank.

30 The project was examined jointly by Hydro Quebec, and the National Research Council. The data used for the evaluation is from Pigeon, René, "Projet d'un mini-parc d'éoliennes aux Iles-de-la-Madelaine - Analyse Technico-économique pour Hydro-Québec (rapport préliminaire)", Conseil national de recherche du Canada, Ottawa, 1982.

31 Based on price of diesel for Magdalen Islands as used in Pigeon, op. cit.; price converted to 1981 dollars and adjusted for the assumption of a $215 per cubic meter crude oil price.

32 Based on quotations of present costs of diesel in Canadian remote communities, available from Northern Canada Power Commission; prices converted to 1981 dollars and adjusted for the assumption of a $215 per cubic meter crude oil price.

33 See Lanmer Consultants (1978) Ltd., op. cit.

34 Prices obtained from Northern Canada Power Commission, and expressed in 1981 dollars.

35 Price taken from Pigeon, op. cit., and expressed in 1981 dollars.

Table 1

Regional Market Prices and Shadow Prices of Energy in the Canadian Residential Sector
Base Case Values for 1995[1]

Province	Market Prices				Shadow Prices[2]			
	Light Fuel Oil[3] (¢/l)	Natural Gas[3] (¢/m^3)	Electricity[4] (¢/kWh)	Wood[5] ($/Odt)	Light Fuel Oil[6] (¢/l)	Natural Gas[7] (¢/m^3)	Electricity[8] 10% (¢/kWh)	Electricity[8] 7% (¢/kWh)
Newfoundland	31	-	4.1	62	33	-	8.7	6.9
Prince Edward Island	29	-	8.0	65	31	-	12.3	9.8
Nova Scotia	29	-	4.3	59	31	26	10.1	8.1
New Brunswick	29	-	3.0	69	31	26	10.1	8.1
Quebec	29	20	3.4	77	31	26	5.4	4.3
Ontario	29	19	3.4	77	31	25	5.1	4.1
Manitoba	29	15	2.3	77	31	21	5.5	4.4
Saskatchewan	28	12	3.1	77	30	20	6.2	4.9
Alberta	28	12	3.3	108	30	19	5.3	4.2
British Columbia	29	14	3.2	59	31	20	6.2	5.0

[1] All prices expressed in 1981 units of currency.

[2] Wood shadow prices assumed equal to current market prices.

[3] Current prices taken from EMR's Statistical Handbook, Update #81 (1983), and converted to 1981 $.

[4] Based on figures from Hydro Quebec, "Comparaison des prix de l'électricité, villes canadiennes et américaines selon les tarifs en vigueur au ler mars 1983", Service de la tarification, Hydro Québec, Montréal, 1983. March 1983 prices (for consumption above the first 1000 kWh per month) expressed in 1981 $. Figure for Manitoba revised to account for price increase effective May 1983.

[5] EMR estimates; prices are for cut, split and delivered firewood in rural areas. Prices expressed in 1981 $ per oven-dry tonne.

[6] Market prices adjusted for the assumption of a $215 (1981 $ Can.) per cubic meter oil price in Montreal.

[7] Market prices (net of taxes) adjusted for the assumption of an 85 per cent gas/oil energy price parity at Toronto city gate.

[8] Based on EMR estimates of the costs of all-thermal power systems using social discount rates of 10% and 7%. See Energy, Mines and Resources Canada, "Energy Reference Cost Premiums", Special Studies Branch, EMR, Ottawa, 1980, and Energy, Mines and Resources Canada, "Conventional Energy Present Value Tables", Renewable Energy Division, Ottawa, 1982.

Table 2

Supply Price of Space Heating Options for New 1995 Homes
Base Case - 10% Discount Rate[1]
(1981 $ per gigajoule of useful heat)

City	Conventional Alternatives Oil	Gas	Electricity	Condensing Gas Furnace	All-Electric Heat Pump (1)	(2)[2]	Central Wood Furnace[3]
St. John's	16.06	-	26.17	-	19.76	16.87	13.53
Charlottetown	15.66	-	36.34	-	24.93	21.92	14.11
Halifax	16.05	13.85	30.44	12.44	23.00	19.63	14.66
Fredericton	15.58	13.48	30.14	11.83	25.26	22.29	14.34
Montreal	15.73	13.61	17.37	12.05	17.90	14.79	15.42
Ottawa	15.35	13.07	16.25	11.56	16.90	13.93	15.03
Toronto	15.81	13.47	16.56	12.21	16.41	13.01	16.27
Winnipeg	15.00	11.04	17.19	9.80	17.36	15.00	13.88
Regina	14.75	10.65	19.10	9.53	18.67	16.32	13.84
Edmonton	14.91	10.38	16.71	9.47	17.31	14.82	16.88
Vancouver	17.15	12.37	20.62	12.53	19.74	15.13	18.25

[1] The base case is defined by letting the shadow prices given in Table 1 remain constant in real terms throughout the investment horizon.

[2] Includes a $1,500 capital cost credit for air conditioning.

[3] Supply prices applicable to rural areas.

Table 3

Supply Price of Space Heating Options for New 1995 Homes
Base Case - 7% Discount Rate[1]
(1981 $ per gigajoule of useful heat)

City	Conventional Alternatives Oil	Gas	Electricity	Condensing Gas Furnace	All-Electric Heat Pump (1)	(2)[2]	Central Wood Furnace[3]
St. John's	15.64	-	20.94	-	16.16	13.83	12.18
Charlottetown	15.23	-	24.08	-	20.31	17.89	12.70
Halifax	15.57	13.37	24.36	11.57	18.81	16.10	13.07
Fredericton	15.15	13.05	24.12	11.07	20.57	18.18	12.95
Montreal	15.28	13.16	13.91	11.24	14.70	12.20	13.96
Ottawa	14.92	12.64	13.00	10.79	13.88	11.49	13.63
Toronto	15.32	12.98	13.26	11.33	13.54	10.81	14.67
Winnipeg	14.62	10.66	13.76	9.13	14.18	12.28	12.65
Regina	14.37	10.28	15.28	8.86	15.22	13.33	12.62
Edmonton	14.51	9.98	13.37	8.77	14.15	12.15	15.59
Vancouver	16.49	11.70	16.51	11.33	16.36	12.65	16.08

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[1] The base case is defined by letting the shadow prices given in Table 1 remain constant in real terms throughout the investment horizon.

[2] Includes a $1,500 capital cost credit for air conditioning.

[3] Supply prices applicable to rural areas.

Table 4

Supply Price of Space Heating Options for New 1995 Homes
High Oil Price Case - 10% Discount Rate[1]
(1981 $ per gigajoule of useful heat)

City	Conventional Alternatives Oil	Gas	Electricity	Condensing Gas Furnace	All-Electric Heat Pump (1)	(2)[2]	Central Wood Furnace[3]
St. John's	20.35	-	29.78	-	21.49	18.60	14.32
Charlottetown	19.96	-	41.46	-	27.39	24.39	14.93
Halifax	20.35	17.53	34.63	14.96	25.01	21.64	15.40
Fredericton	19.88	17.16	34.34	14.35	27.78	24.82	15.21
Montreal	20.03	17.29	19.64	14.57	19.26	16.16	16.39
Ottawa	19.65	16.75	18.36	14.08	18.17	15.20	16.00
Toronto	20.11	17.15	18.67	14.73	17.42	14.02	17.24
Winnipeg	19.31	14.72	19.48	12.32	18.96	16.60	14.85
Regina	19.05	14.33	21.67	12.05	20.47	18.12	14.81
Edmonton	19.21	14.06	18.91	11.99	18.85	16.36	18.25
Vancouver	21.46	16.05	23.21	15.05	20.74	16.12	18.99

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[1] The high oil price case is defined by adding a set of premiums to the energy shadow prices given in Table 1. The premiums for heavy fuel oil and natural gas are 11¢/l and 9¢/m^3 respectively; for electricity and wood, the premiums in each region are set equal to a 15 per cent fraction of the corresponding base case values. The resulting energy shadow prices are assumed to remain constant in real terms throughout the post- 1995 investment horizon.

[2] Includes a $1,500 capital cost credit for air conditioning.

[3] Supply prices applicable to rural areas.

Table 5

Break-Even Electricity Costs for Space Heating in New 1995 Homes
Base Case - 10% Discount Rate[1]
(1981 ¢/kWh)

City	Electric Resistance vs Least-Cost Conventional System[2]	Electric Resistance vs Least-Cost System[3]	All Electric Heat Pump vs Least-Cost Conventional System[2]	All Electric Heat Pump vs Least-Cost System[3]	All Electric Heat Pump vs Least-Cost Conventional System[2]	All Electric Heat Pump vs Least-Cost System[3]
St. John's	5.0	4.1	6.0	4.1	8.1	6.2
Charlottetown	4.8	4.3	5.3	4.2	7.6	6.4
Halifax	4.9	4.4	4.9	3.8	7.4	6.3
Fredericton	4.8	4.4	4.1	3.4	6.1	5.3
Montreal	4.1	3.5	2.8	1.9	4.7	3.8
Ottawa	3.9	3.4	2.7	1.8	4.6	3.6
Toronto	3.9	3.5	2.9	1.9	5.4	4.5
Winnipeg	3.3	2.8	2.2	1.6	3.5	2.8
Regina	3.1	2.7	2.0	1.5	3.3	2.7
Edmonton	3.0	2.7	1.7	1.2	3.0	2.5
Vancouver	3.2	3.2	0.0	0.0	3.6	3.6

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[1] The break-even costs represent the constant real cost (or shadow price) of electricity at which the electricity-based heating options become competitive (on a supply price basis) with either oil, gas, or wood heating systems.

[2] Conventional oil furnace in the maritimes, conventional gas furnace in all other provinces.

[3] Central wood furnace in the Maritimes (applicable to rural areas only), condensing gas furnace in Quebec, Ontario and the Prairies and conventional gas furnace in British Columbia.

Table 6

Break-Even Electricity Costs for Space Heating in New 1995 Homes
High Oil Price Case - 10% Discount Rate[1]
(1981 ¢/kWh)

City	Electric Resistance vs Least-Cost Conventional System[2]	Electric Resistance vs Least-Cost System[3]	All Electric Heat Pump vs Least-Cost Conventional System[2]	All Electric Heat Pump vs Least-Cost System[3]	All Electric Heat Pump vs Least-Cost Conventional System[2]	All Electric Heat Pump vs Least-Cost System[3]
St. John's	6.6	4.4	9.1	4.6	11.3	6.7
Charlottetown	6.4	4.6	8.6	4.8	10.8	7.0
Halifax	6.4	4.7	8.1	4.4	10.6	6.9
Fredericton	6.4	4.7	6.8	4.1	8.6	5.8
Montreal	5.4	4.4	5.1	3.4	6.9	5.3
Ottawa	5.2	4.3	5.0	3.4	6.7	5.2
Toronto	5.3	4.4	5.6	3.8	8.2	6.4
Winnipeg	4.6	3.7	4.1	2.9	5.3	4.1
Regina	4.5	3.6	4.0	2.8	5.2	4.0
Edmonton	4.3	3.6	3.6	2.5	4.9	3.8
Vancouver	4.6	4.2	2.7	1.8	7.0	6.1

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[1] The break-even costs represent the constant real cost (or shadow price) of electricity at which the electricity-based heating options become competitive (on a supply price basis) with either oil, gas, or wood heating systems.

[2] Conventional oil furnace in the Maritimes, conventional gas furnace in all other provinces.

[3] Central wood furnace in the Maritimes (applicable to rural areas only), condensing gas furnace in all other provinces.

Table 7

Private Supply Prices of Space Heating Options for New 1995 Homes
20 Year Investment Horizon[1]
(1981 $ per gigajoule of useful heat)

City	Conventional Alternatives Oil	Gas	Electricity	Condensing Gas Furnace	All-Electric Heat Pump (1)	(2)[2]	Central Wood Furnace[3]
St. John's	14.35	-	12.81	-	11.27	9.54	10.96
Charlottetown	13.92	-	23.54	-	16.62	14.74	11.83
Halifax	14.19	-	13.47	-	12.43	10.32	11.60
Fredericton	13.89	-	9.81	-	10.99	9.13	11.71
Montreal	13.99	10.27	10.88	8.90	11.87	9.92	12.59
Ottawa	13.65	9.78	10.85	8.48	11.62	9.76	12.33
Toronto	13.98	10.04	11.04	8.92	11.32	9.19	13.18
Winnipeg	13.38	7.86	7.68	6.91	9.22	7.74	11.50
Regina	13.13	6.56	9.74	6.02	10.63	9.16	11.47
Edmonton	13.24	6.62	10.33	6.15	11.28	9.72	14.47
Vancouver	14.90	8.48	11.10	8.58	12.64	9.75	14.07

1 Supply prices calculated using a real discount rate of 4 per cent. The market prices of energy used in the calculations are as given in Table 1 (values held constant in real terms throughout the investment horizon).

2 Includes a $1,500 capital cost credit for air conditioning.

3 Supply prices applicable to rural areas.

Table 8

Private Supply Prices of Space Heating Options for New 1995 Homes
5 Year Investment Horizon[1]
(1981 $ per gigajoule of useful heat)

City	Conventional Alternatives			Condensing Gas Furnace	All-Electric Heat Pump		Central Wood Furnace[3]
	Oil	Gas	Electricity		(1)	(2)[2]	
St. John's	17.19	-	15.54	-	19.70	14.17	19.86
Charlottetown	16.87	-	26.37	-	25.38	19.64	21.08
Halifax	17.51	-	16.65	-	22.25	15.81	21.97
Fredericton	16.81	-	12.61	-	19.64	13.96	20.84
Montreal	17.05	13.33	13.81	14.18	20.93	14.98	22.16
Ottawa	16.58	12.70	13.65	13.53	20.28	14.60	21.48
Toronto	17.33	13.39	14.25	14.70	21.24	14.73	23.66
Winnipeg	15.96	10.44	10.16	11.31	16.10	11.58	14.55
Regina	15.70	9.14	12.20	10.40	17.47	12.98	14.48
Edmonton	15.97	9.34	12.95	10.78	18.52	13.77	22.95
Vancouver	19.45	13.02	15.46	16.42	26.11	17.28	28.29

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[1] Supply prices calculated using a real discount rate of 4 per cent. The market prices of energy used in the calculations are as given in Table 1 (values held constant in real terms throughout the investment horizon).

[2] Includes a $1,500 capital cost credit for air conditioning.

[3] Supply prices applicable to rural areas.

Table 9

Regional Market Prices and Shadow Prices of Energy in the Canadian Industrial Sector
Base Case Values for 1995[1]

Province	Market Prices[2]			Shadow Prices			
	Heavy Fuel Oil (¢/l)	Natural Gas (¢/m^3)	Electricity (¢/kWh)	Heavy Fuel Oil[3] (¢/l)	Natural Gas[4] (¢/m^3)	Electricity[5] 10% (¢/kWh)	Electricity[5] 7% (¢/kWh)
1 Conventional Energy							
Newfoundland	20	-	3.3	22	-	7.6	6.1
Prince Edward Island	20	-	8.0	22	-	11.5	9.2
Nova Scotia	20	-	3.6	22	21	9.1	7.2
New Brunswick	20	-	3.3	22	21	9.1	7.2
Quebec	17	15	2.6	19	21	4.5	3.6
Ontario	18	14	2.8	19	19	4.3	3.4
Manitoba	17	11	1.9	19	17	4.8	3.8
Saskatchewan	17	10	3.0	19	15	5.7	4.6
Alberta	17	7	2.4	19	14	4.5	3.6
British Columbia	14	10	2.1	16	16	4.9	3.9

2 Biomass Wastes

(Market prices and shadow prices assumed equal for all regions)

- Logging Residues : $45/oven-dry tonne[6]
- Sawmill and Paper Mill Waste
  - used on-site : zero cost
  - delivered to user : $16.50/oven-dry tonne[7]
- Municipal Solid Wastes : $4 to $12 per tonne credit, avoided landfill cost.

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[1] All prices expressed in 1981 units of currency.

[2] Current prices taken from EMR's Statistical Handbook, Update #81 (1983), and converted to 1981 $.

[3] Market prices adjusted for the assumption of a $215 (1981 $ Can.) per cubic meter oil price in Montreal.

[4] Market prices adjusted for the assumption of an 85 per cent gas/oil energy price parity at Toronto city gate.

[5] Based on EMR estimates of the costs of all-thermal power systems using social discount rates of 10 per cent and 7 per cent. See Energy, Mines and Resources Canada, "Energy Reference Cost Premiums", Special Studies Branch, EMR, Ottawa, 1980, and Energy, Mines and Resources Canada, "Conventional Energy Present Value Tables", Renewable Energy Division, Ottawa, 1982.

[6] Prices based on the following studies: Intergroup Consulting Economists Ltd., Availability and Cost of Forest Biomass in Canada, ENFOR Project P-224(1), Winnipeg, 1982; and Peat, Marwick and Partners Management Consultants, Wood Production and Conversion in Eastern Ontario, Summary Report, for the Ontario Ministry of Energy, Toronto, 1982.

[7] Authors' estimate; $0.33/tonne-km and average haul distance of 50 km.

Table 10

Supply Price Evaluation of 202 Cogeneration Projects - Distribution of Regional Capacity and Production Potential[1]
(10% discount rate)

Supply Price Range (1981 mills per kWh)	Nova Scotia Cap MW	Nova Scotia Prod GWh	New Brunswick Cap MW	New Brunswick Prod GWh	Quebec Cap MW	Quebec Prod GWh	Ontario Cap MW	Ontario Prod GWh	Manitoba Cap MW	Manitoba Prod GWh	Saskatchewan Cap MW	Saskatchewan Prod GWh	Alberta Cap MW	Alberta Prod GWh	British Columbia Cap MW	British Columbia Prod GWh	Total[2] Cap MW	Total[2] Prod GWh
1. **Base Case**[3]																		
< 30					102	815	314	2433	18	145	13	104	280	2240	444	3077	1171	8814
30-34.9	116	779	80	532	319	2447	166	1240	22	175	20	148	28	213	86	584	837	6118
35-39.9					88	578	96	710					12	63	23	143	223	1526
40-44.9			8	52	24	171	36	191					16	45	11	69	91	496
> 45	3	22	4	13	31	122	50	200	4	18	5	30	22	39	12	57	131	501
Total	119	801	92	597	564	4133	662	4774	44	338	38	282	358	2600	576	3930	2453	17455
2. **High Oil Price Case**[4]																		
< 30					52	382							20	157	21	161	93	700
30-34.9													146	1219	118	884	264	2103
35-39.9					29	221	227	1755	18	145	13	104	110	833	358	2355	755	5413
40-44.9	116	779	80	532	334	2616	238	1808	22	175	20	148	32	244	33	261	875	6563
45-49.9					87	592	97	715					12	63	26	167	222	1537
50-54.9			4	32	30	201	50	296					16	45	2	18	102	592
> 55	3	22	8	33	32	121	50	200	4	18	5	30	22	39	18	84	142	547
Total	119	801	92	597	564	4133	662	4774	44	338	38	282	358	2600	576	3930	2453	17455

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[1] Natural gas assumed as incremental fuel.

[2] Cogeneration data not available for Newfoundland and Prince Edward Island.

[3] The base case is defined by letting the shadow prices given in Table 9 remain constant in real terms throughout the investment horizon.

[4] The high oil price case is defined by adding a set of premiums to the energy shadow prices given in Table 9. The premium for natural gas is 9¢/m^3; for electricity, the premium in each region is set equal to a 15 per cent fraction of the corresponding base case value.

Table 11

Technical, Economic and Commercial Potential for Cogeneration vs Total System Capacity and Implemented Cogeneration Capacity

	Total System Capacity (1981)[1] (MW)	Implemented Cogeneration[2]		Technical Potential[3]		Economic Potential[4]		Commercial Potential[5]	
		(MW)	% of System Capacity	(MW)	% of System Capacity	(MW)	% of Technical Potential	(MW)	% of Economic Potential
Newfoundland[6]	6959	-	-	-	-	-	-	-	-
Prince Edward Island[6]	118	-	-	-	-	-	-	-	-
Nova Scotia	2029	90	4.4	224	11.0	224	100.0	150	67.0
New Brunswick	2792	45	1.6	138	4.9	138	100.0	120	87.0
Quebec	21924	35	0.2	670	3.1	633	95.5	188	29.7
Ontario	25752	211	0.8	1509	5.9	1395	92.4	879	63.0
Manitoba	4142	12	0.3	59	1.4	54	91.5	0	0.0
Saskatchewan	2336	0	0.0	50	2.1	43	86.0	43	100.0
Alberta	6201	47	0.8	452	7.3	425	94.0	219	51.5
British Columbia	10762	329	3.0	1048	9.7	1025	98.0	340	33.2
Canada (excluding Nfld and P.E.I.)	75938	769	1.0	4150	5.5	3937	94.9	1939	49.3

[1] Statistics Canada, 57-202 (1981).

[2] Extrapolated from 1981 data on 202 industrial plants. See Acres Consulting Services Limited, An Economic Update of the Potential for Cogeneration in Canada, Industrial Steam Turbines, Industry Series, Publication No. la, Energy, Mines and Resources Canada, Ottawa, 1982.

[3] Ibid.; Potential assumed limited to industrial users requiring at least 100,000 pounds per hour of steam.

[4] Cogeneration projects defined as economic when the supply price is less than the corresponding regional shadow price of electricity as given in Table 9; figures extrapolated from the base case results for 202 cogeneration projects as given in Table 10.

[5] Projects defined as commercially viable when payback (for the cogenerator) is less than 5 years; totals extrapolated from results for 202 cogeneration projects as given in Table 14.

[6] Cogeneration data not available for Newfoundland and Prince Edward Island.

Table 12

Technical, Economic and Commercial Potential for Cogeneration vs Total System Generation and Implemented Cogeneration

	Total System Generation (1981)[1] (GWh)	Implemented Cogeneration[2]		Technical Potential[3]		Economic Potential[4]		Commercial Potential[5]	
		(GWh)	% of Total Generation	(GWh)	% of Total Generation	(GWh)	% of Technical Potential	(GWh)	% of Economic Potential
Newfoundland[6]	44767	-	-	-	-	-	-	-	-
Prince Edward Island[6]	31	-	-	-	-	-	-	-	-
Nova Scotia	6577	521	7.9	1506	22.9	1506	100.0	981	65.1
New Brunswick	8994	271	3.0	896	10.0	896	100.0	798	89.1
Quebec	103175	209	0.2	4918	4.8	4773	97.1	1429	29.9
Ontario	110978	1381	1.2	10880	9.8	10424	95.8	6721	64.5
Manitoba	18384	81	0.4	449	2.4	425	94.7	-	0.0
Saskatchewan	9683	0	0.0	363	3.7	324	89.3	324	100.0
Alberta	25570	335	1.3	3275	12.8	3225	99.4	1748	54.2
British Columbia	51087	2063	4.0	7154	14.0	7050	98.5	2589	36.7
Canada (excluding Nfld and P.E.I.)	334448	4861	1.5	29441	8.8	28623	97.2	14590	50.9

[1] Statistics Canada, 57-202 (1981).

[2] Extrapolated from 1981 data on 202 industrial plants. See Acres Consulting Services Limited, An Economic Update of the Potential for Cogeneration in Canada, Industrial Steam Turbines, Industry Series, Publication No. 1a, Energy, Mines and Resources Canada, Ottawa, 1982.

[3] Ibid.; data limited to industrial users requiring at least 100,000 pounds per hour of steam.

[4] Cogeneration projects defined as economic when the supply price is less than the corresponding regional shadow price of electricity as given in Table 9; figures extrapolated from the base case results for 202 cogeneration projects, as given in Table 10.

[5] Projects defined as commercially viable when payback (for the cogenerator) is less than 5 years; totals extrapolated from results for 202 cogeneration projects as given in Table 14.

[6] Cogeneration data not available for Newfoundland and Prince Edward Island.

Table 13

Economic Potential for Cogeneration Under Different Assumptions on Energy Shadow Prices and Discount Rate[1]

Province	Base Case [2]				High Oil Price Case[3]			
	10% Discount Rate		7% Discount Rate		10% Discount Rate		7% Discount Rate	
	Units	% of Technical Potential	Units	% of Technical Potential	Units	% of Technical Potential	Units	% of Technical Potential
1 Capacity (MW)								
Nova Scotia	224	100	224	100	224	100	224	100
New Brunswick	138	100	138	100	138	100	138	100
Quebec	633	95	572	85	608	91	397	59
Ontario	1395	92	1125	75	1237	82	621	41
Manitoba	54	92	54	92	54	92	54	92
Saskatchewan	43	86	43	86	43	86	43	86
Alberta	425	94	394	87	407	90	386	85
British Columbia	1025	98	1011	97	1015	97	982	94
Canada (excluding Nfld. and P.E.I.)[4]	3936	95	3561	86	3726	90	2845	69
2 Production (GWh)								
Nova Scotia	1506	100	1506	100	1506	100	1506	100
New Brunswick	896	100	896	100	896	100	896	100
Quebec	4773	97	4384	89	4598	93	3087	63
Ontario	10424	96	8592	79	9422	87	4824	44
Manitoba	425	95	425	95	425	95	425	95
Saskatchewan	324	89	324	89	324	89	324	89
Alberta	3225	98	3125	95	3186	97	3062	93
British Columbia	7050	99	6966	97	6998	98	6792	95
Canada (excluding Nfld and P.E.I.)[4]	28623	97	26218	89	27355	93	20916	71

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[1] Cogeneration projects defined as economic when the supply price is less than the corresponding regional shadow price of electricity.

[2] The base case is defined by letting the shadow prices given in Table 9 remain constant in real terms throughout the investment horizon.

[3] The high oil price case is defined by adding a set of premiums to the energy shadow prices given in Table 9. The premium for natural gas is 9¢/m^3; for electricity, the premium in each region is set equal to a 15 per cent fraction of the corresponding base case value.

[4] Cogeneration data not available for Newfoundland and Prince Edward Island.

Table 14

Financial Analysis of 202 Cogeneration Projects - Distribution of Capacity and Production Potential[1]

	Nova Scotia		New Brunswick		Quebec		Ontario		Manitoba		Saskatchewan		Alberta		British Columbia		Total[2]	
1 Payback																		
Range (years)	Cap MW	Prod GWh	Cap MW	Prod GWh	Cap MW	Prod GWh	Cap MW	Prod GWh	Cap MW	Prod GWh	Cap MW	Prod GWh	Cap MW	Prod GWh	Cap MW	Prod GWh	Cap MW	Prod GWh
0-5	80	522	80	532	158	1201	385	2948			33	252	174	1387	187	1377	1097	8219
5.1-10	15	118			123	939	30	206					51	405	187	1127	406	2795
11.1-20	18	115	8	52	218	1651	172	1290	26	128			54	410	137	1015	633	4661
> 20	6	46	4	13	65	342	75	330	18	210	5	30	79	398	65	411	317	1780
Total	119	801	92	597	564	4133	662	4774	44	338	38	282	358	2600	576	3930	2453	17455
2 Return on Equity[3]																		
Range (%)																		
0-14.9	24	161	12	65	264	1846	246	1620	44	338	5	30	133	807	183	1280	911	6147
15-19.9	15	118			142	1085	30	206					51	405	206	1274	444	3088
20-29.9			28	204	106	819	244	1835			5	36	76	572	136	994	595	4460
> 30	80	522	52	328	52	383	142	1113			28	216	98	816	51	382	503	3760
Total	119	801	92	597	564	4133	662	4774	44	338	38	282	358	2600	576	3930	2453	17455

[1] Natural gas assumed as incremental fuel. The market prices of energy used in the calculations are as given in Table 9 (values held constant in real terms throughout the investment horizon).

[2] Cogeneration data not available for Newfoundland and Prince Edward Island.

[3] Rates of return given in nominal terms; a 6 per cent long-run annual rate of inflation is assumed.

Table 15

Financial Analysis of Cogeneration Projects in the Pulp and Paper Industries
Distribution of Capacity and Production Potential[1]

	Incremental Fuel Used					
	Natural Gas		Logging Residues[2]		On-Site Wastes	
	Capacity (MW)	Production (GWh)	Capacity (MW)	Production (GWh)	Capacity (MW)	Production (GWh)
Payback (years)						
0-5	590	4258	1059	7581	1211	8698
5.1-10	269	1757	94	676	5	24
10.1-20	324	2480	30	239		
>20	33	227	5	28		
Total	1216	8722	1188	8524	1216	8722
Return on Equity (%)[3]						
0-14.9	300	2274	24	178	3	12
15-19.9	326	2190	105	765	2	12
20-29.9	279	2057	290	1910	6	39
>30	311	2207	769	5671	1205	8659
Total	1216	8722	1188	8524	1216	8722

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[1] The market prices of energy used in the calculations are as given in Table 9 (values held constant throughout the investment horizon).

[2] Pulp and paper mills only.

[3] Rates of return given in nominal terms; a 6 per cent long-run annual rate of inflation is assumed.

Table 16

Supply Price Distribution of 31 Waste Heat Recovery Projects (10% discount rate)

Supply Price Range (1981 $/GJ)[1]	Projects
0.0 - 0.50	14
0.50 - 1.0	12
1.0 - 2.0	2
2.0 - 3.0	
3.0 - 4.0	1
4.0 - 5.0	2
	31

Range of supply prices: $0.02/GJ to $4.86/GJ

Mean supply price: $0.839/GJ

Weighted mean supply price: $0.417/GJ[2]

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[1] Costs expressed in dollars per gigajoule of secondary energy. To convert in dollars per unit of fuel displaced, divide by a factor of 26.88 for natural gas, or by a factor of 24 for heavy fuel oil

[2] Weights represented by energy savings.

Table 17

Estimate of the Potential for Waste Heat Recovery in Canadian Manufacturing and Mining[1]

Province	Energy Consumption	Technical Potential for Waste Heat Recovery[2]	Economic Potential for Waste Heat Recovery[3]
		(PJ)	(PJ)
Newfoundland	34.8	3.8	1.6
Prince Edward Island	0.4	-	-
Nova Scotia	43.5	4.7	2.0
New Brunswick	37.8	4.1	1.7
Quebec	398.9	43.1	18.0
Ontario	652.4	70.5	29.4
Manitoba	34.4	3.7	1.5
Saskatchewan	55.6	6.0	2.5
Alberta	220.5	23.8	9.9
British Columbia	186.9	20.2	8.4
	1665.2	179.9	75.0

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[1] Statistics Canada, 57-003. 1082-IV.

[2] See Lalonde, Girouard, Letendre and Associates Ltd., Energy Cascading Potential in Canadian Industry, Data Base for 1978, Industry Series, Publication #3a, Energy, Mines and Resources Canada, December 1981; technical recovery factor for manufacturing and mining (10.8%) applied to 1982 industrial energy consumption.

[3] Based on a factor of 4.5 per cent of total energy consumption in manufacturing and mining; the factor is based on estimates available in Diener, S.G. and B. James, "A comparison of the Costs of Energy Conservation and Energy Supply in Canada", Energy, Mines and Resources Canada, Ottawa, May 1981.

Table 18

Results of Regional Financial Analysis for a Sample of Waste Heat Recovery Projects[1]

Project Data

Project	Investment ($)	Annual Energy Savings[2] (GJ)	Supply Price[2] ($/GJ)
1	111,600	21,700	.68
2	42,300	6,100	.91
3	110,000	4,700	3.08
4	20,900	600	4.58

Financial Analysis[3]

Region	Natural Gas Displaced							
	Project 1		Project 2		Project 3		Project 4	
	Payback (years)	ROE (%)	Payback (years)	ROE (%)	Payback (years)	ROE (%)	Payback (years)	ROE (%)
Maritimes	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Quebec	1.6	60.4	2.0	47.8	4.7	17.8	6.6	11.9
Ontario	1.8	54.8	2.2	43.4	5.3	15.8	7.3	10.3
Manitoba	1.9	50.0	2.3	39.7	5.8	14.1	8.0	8.8
Saskatchewan	2.2	43.8	2.6	34.7	6.7	11.7	9.2	6.8
Alberta	2.7	32.0	3.3	25.2	9.3	6.7	12.4	2.5
B.C.	2.0	48.3	2.4	38.3	6.0	13.5	8.3	8.3

	Heavy Fuel Oil Displaced							
	Project 1		Project 2		Project 3		Project 4	
	Payback (years)	ROE (%)	Payback (years)	ROE (%)	Payback (years)	ROE (%)	Payback (years)	ROE (%)
Maritimes	1.5	68.0	1.8	53.7	4.1	20.4	5.8	14.0
Quebec	1.7	58.0	2.1	46.3	4.9	17.2	6.8	11.4
Ontario	1.6	60.0	2.0	48.2	4.7	18.0	6.6	12.1
Manitoba	1.6	60.0	2.0	48.2	4.7	18.0	6.6	12.1
Saskatchewan	1.6	60.0	2.0	48.2	4.7	18.0	6.6	12.1
Alberta	1.6	60.0	2.0	48.2	4.7	18.0	6.6	12.1
B.C.	1.9	51.0	2.3	40.6	5.7	14.5	7.9	9.2

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1 The market prices of energy used in the calculations are as given in Table 9 (values held constant in real terms throughout the investment horizon).

2 Gigajoule figures refer to input energy (i.e., secondary energy displaced).

3 Rates of return given in nominal terms; a 6 per cent long-run annual rate of inflation is assumed.

Table 19

Supply Prices for Industrial Process Steam from Energy-From-Waste Plants[1]
(10% discount rate)

Fuel Mix[2]	Average Fuel Cost $/tonne	Supply Prices $ per litre of heavy fuel oil	 $ per m^3 of natural gas	 $ per gigajoule[3]
100 % MSW	-12.00	.12	.11	2.96
	-8.00	.15	.13	3.49
	-4.00	.16	.14	3.76
50 % MSW - 50 % Sawmill Waste	2.25	.19	.17	4.57
	4.25	.19	.17	4.57
	6.25	.20	.18	4.84
100 % Sawmill Waste	12.50	.20	.18	4.84
	16.50	.21	.19	5.11
	20.50	.24	.21	5.64

[1] Supply prices expressed in 1981 $ per unit.

[2] The supply prices include capital cost and O&M cost adjustments across different fuel mixes. Capital and O&M costs are less if greater fractions of wood (i.e., sawmill wastes) are utilized.

[3] Gigajoules refer to secondary energy units.

Table 20

Estimate of the Technical Potential and Economic Potential for Energy-from-Waste Plants in Canada (PJ/year)

Province	Technical Potential[1]				Economic Potential[2]			
	100 % MSW	50 - 50 Mix	100 % Sawmill Waste	Total	100 % MSW	50 - 50 Mix	100 % Sawmill Waste	Total
Newfoundland	1.0	-	-	1.0	1.0	-	-	1.0
Prince Edward Island	-	-	-	-	-	-	-	-
Nova Scotia	1.5	-	-	1.5	1.5	-	-	1.5
New Brunswick	0.7	-	-	0.7	0.7	-	-	0.7
Quebec	13.1	3.4	2.4	18.9	13.1	1.7	1.2	16.0
Ontario	24.9	0.2	-	25.1	24.9	0.1	-	25.0
Manitoba	2.4	-	-	2.4	2.4	-	-	2.4
Saskatchewan	1.9	0.5	-	2.4	1.9	-	-	1.9
Alberta	5.6	0.7	-	6.3	5.6	-	-	5.6
British Columbia	4.6	2.9	2.7	10.2	4.6	-	-	4.6
Canada	55.7	7.7	5.1	68.5	55.7	1.8	1.2	58.7

[1] Totals estimated by relating provincial and sub-provincial supplies of MSW and sawmill wastes to corresponding (regional) demands for industrial process steam.

[2] EFW projects defined as economic when the supply price is less than the corresponding (regional) shadow prices of natural gas and/or oil (see Table 9). The above values are based on the base case supply price analysis, as given in Table 19. For the high oil price case, the economic potential equals the technical potential defined above.

Table 21

Regional Financial Analysis of an Energy-from-Waste Plant[1]

Region	Credit for Avoided Landfill Costs (tipping fee) ($/tonne of waste)	Fuel Displaced			
		Heavy Fuel Oil		Natural Gas	
		Payback (years)	ROE[2] (%)	Payback (years)	ROE[2] (%)
Maritimes	12	1.5	60	N/A	N/A
	8	2.0	50	N/A	N/A
	4	2.7	39	N/A	N/A
Quebec	12	2.1	47	2.1	47
	8	3.0	37	3.0	37
	4	5.0	26	5.0	26
Ontario	12	1.9	52	2.5	42
	8	2.6	41	3.8	31
	4	5.0	26	5.0	26
Manitoba	12	1.6	56	3.7	31
	8	2.2	46	6.7	20
	4	3.2	35	13.9	8
Saskatchewan	12	1.6	56	6.0	22
	8	2.2	46	12.3	10
	4	3.2	35	-	-
Alberta	12	1.6	56	13.7	8
	8	2.2	46	-	-
	4	3.2	35	-	-
British Columbia	12	3.0	36	5.2	25
	8	5.0	25	10.5	13
	4	10.0	14	-	-

(-) Indicates payback greater than 20 years or negative rate of return on equity.

[1] The market prices of energy used in the calculations are as given in Table 9 (values held constant throughout the investment horizon).

[2] Rates of return given in nominal terms; a 6 per cent long-run annual rate of inflation is assumed.

Table 22

Regional Market Prices and Shadow Prices of Transportation Fuels
Base Case Values for 1995[1]

Province	Market Prices Gasoline[2] (¢/l)	Diesel[3] (¢/l)	Propane[4] (¢/l)	CNG[5] (¢/m^3)	Shadow Prices Gasoline[6] (¢/l)	Diesel[7] (¢/l)	Propane[8] (¢/l)	CNG[9] (¢/m^3)	Methanol[10] (¢/l)
Newfoundland	47	46	30	-	34	30	25	-	26
Prince Edward Island	46	47	30	-	34	20	25	-	26
Nova Scotia	44	41	30	-	33	29	25	30	25
New Brunswick	43	42	30	-	34	30	24	30	26
Quebec	47	43	37	24	32	28	24	30	24
Ontario	38	38	23	22	30	26	22	28	22
Manitoba	40	38	27	20	32	28	22	26	22
Saskatchewan	34	31	23	17	32	28	22	22	22
Alberta	34	30	22	15	32	28	21	22	22
British Columbia	40	39	26	19	32	28	25	24	22

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[1] All prices expressed in 1981 currency.

[2] From EMR's Statistical Handbook, Update #81, and converted to 1981 $.

[3] Based on mid-83 pump prices in selected cities; from EMR, Petroleum Product Marketing Division.

[4] Based on mid-83 pump prices in selected cities; from EMR, NGL Division.

[5] Prices obtained by adding a 6 cent premium to the market price of natural gas for the commercial sector. The premium accounts for the cost of compression and distribution.

[6] Mid-83 pump prices net of taxes and adjusted for the assumption of a $215 (1981 $ Can.) per cubic meter oil price in Montreal.

[7] Based on an 85 per cent diesel/gasoline price parity (per unit of volume) at the refinery gate.

[8] Estimates of the propane pump price net of taxes.

[9] Prices obtained by adding a 6 cent premium to the estimated shadow price of natural gas for the commercial sector (based on an 85 per cent gas/oil energy price parity at Toronto city gate).

[10] Prices include production and distribution; authors' estimates.

Table 23

Regional Supply Prices of Transportation Fuels
Base Case - 10% Discount Rate[1]
(1981 ¢ per litre of gasoline supplied or displaced).

	Gasoline	Diesel	Propane	CNG	Methanol
1. Private Automobile					
Newfoundland	34	37	40	-	47
Prince Edward Island	34	37	40	-	46
Nova Scotia	33	36	39	47	45
New Brunswick	34	37	39	47	47
Quebec	32	36	39	47	44
Ontario	30	34	36	44	40
Manitoba	32	35	36	42	40
Saskatchewan	32	36	36	39	41
Alberta	32	36	34	39	41
British Columbia	32	36	40	41	41
2. Fleet Automobile					
Newfoundland	34	28	36	-	46
Prince Edward Island	34	28	36	-	45
Nova Scotia	33	27	35	38	44
New Brunswick	34	28	35	38	45
Quebec	32	27	35	38	43
Ontario	30	25	32	35	39
Manitoba	32	26	32	33	39
Saskatchewan	32	27	32	30	30
Alberta	32	27	30	29	40
British Columbia	32	27	36	32	39

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[1] The base case is defined by letting the shadow prices given in Table 22 remain constant in real terms throughout the investment horizon.

Table 24

Regional Supply Prices of Transportation Fuels
High Oil Price Case - 10% Discount Rate[1]
(1981 ¢ per litre of gasoline)

	Gasoline	Diesel	Propane	CNG	Methanol
1. Private Automobile					
Newfoundland	49	44	47	-	54
Prince Edward Island	49	44	47	-	54
Nova Scotia	48	43	47	56	53
New Brunswick	49	44	46	56	54
Quebec	47	43	46	56	52
Ontario	45	41	43	54	47
Manitoba	47	42	43	52	47
Saskatchewan	47	43	43	48	48
Alberta	47	43	41	48	48
British Columbia	47	43	48	50	48
2. Fleet Automobile					
Newfoundland	49	35	43	-	53
Price Edward Island	49	35	43	-	52
Nova Scotia	48	34	43	47	51
New Brunswick	49	35	42	47	53
Quebec	47	34	42	47	50
Ontario	45	32	40	45	46
Manitoba	47	33	39	42	46
Saskatchewan	47	34	39	39	46
Alberta	47	34	37	39	47
Bristish Columbia	47	34	44	41	46

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[1] The high oil price case is defined by adding a set of premiums to the energy shadow prices given in Table 22. The premiums are: 12.7¢/l for gasoline, 10.8¢/l for diesel, 5.4¢/l for propane, 8.9¢/m^3 for CNG and 4.3¢/l for methanol. The resulting energy shadow prices are assumed to remain constant in real terms throughout the post-1995 investment horizon.

Table 25

Commercial Analysis of Alternative Transportation Fuels for Fleet Automobiles[1]

	Fuel Conversion					
	Diesel		Propane		CNG	
	Payback (years)	ROE[2] (%)	Payback (years)	ROE[2] (%)	Payback (years)	ROE[2] (%)
Newfoundland	3.5	13	3.1	17	N/A	N/A
Prince Edward Island	3.7	11	3.4	14	N/A	N/A
Nova Scotia	3.5	13	3.3	15	N/A	N/A
New Brunswick	3.7	10	4.2	5	N/A	N/A
Quebec	3.1	17	–	–	N/A	N/A
Ontario	4.0	7	0.0[3]	∞[3]	1.4	64
Manitoba	3.7	10	3.3	15	1.2	82
Saskatchewan	4.1	7	4.2	5	2.1	37
Alberta	3.8	9	2.6	26	2.4	31
British Columbia	3.8	9	2.5	27	2.2	36
					1.8	47

(-) undefined payback or negative rate of return on equity.

[1] The market prices of energy used in the calculations are as given in Table 22 (values held constant in real terms throughout the investment horizon).

[2] The rates of return are given in nominal terms; a 6 per cent long-run annual rate of inflation is assumed.

[3] In Ontario, conversions to propane are entirely financed by provincial and federal subsidies; annual savings are in the order of $400 (1981 $) per year.

Table 26

Economic and Commercial Analysis of Three Small Hydro Projects

1. Economic Analysis[1]

Project	Capacity (MW)	Annual Energy Production (GWh)	Supply Price (1981 ¢/kWh)
1	2.75	20.5	2.0
2	2.04	9.0	3.0
3	0.66	2.9	9.0

2. Commercial Analysis[2]

	(1) 2.75 MW		(2) 2.04 MW		(3) 0.66 MW	
Province	Payback (Years)	ROE[3] (%)	Payback (Years)	ROE[3] (%)	Payback (Years)	ROE[3] (%)
Newfoundland	1	90	4	38	28	7
Prince Edward Island	n.a.	n.a.	n.a	n.a.	n.a.	n.a.
Nova Scotia	2	71	6	28	31	6
New Brunswick	2	75	6	30	30	6
Quebec	3	47	11	19	35	4
Ontario	2	54	9	22	33	5
Manitoba	8	23	20	12	44	2
Saskatchewan	2	75	6	30	30	6
Alberta	5	33	15	16	39	3
British Columbia	5	33	15	16	39	3

[1] Economic analysis based on a 10 per cent real discount rate. The supply prices can be compared to the regional shadow prices of electricity for the industrial sector, as given in Table 9.

[2] The market prices of electricity used in the calculations are as given in Table 9 (values held constant throughout the investment horizon).

[3] The rates of return are given in nominal terms; a 6 per cent long-run annual rate of inflation is assumed.

Table 27

Economic Evaluation of Four Geothermal Energy Projects

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1. Base Case Natural Gas Shadow Prices (1981¢/m^3)

Province	Residential Sector	Commercial Sector	Industrial Sector
Manitoba	21	20	17
Saskatchewan	20	16	15
Alberta	19	16	14
British Columbia	20	18	16

2. Supply Prices of Geothermal Energy Projects (10% discount rate)

Project	Application	Natural Gas Displaced (m^3)	Supply Price (1981¢/m^3)
1	Residential Townhouse Space and Water Heating	1180	42
2	Commercial Space and Water Heating	3360	16
3	Greenhouse Heating	3225	13
4	Mine Ventilation Air Heating	3200	12

---

[1] The natural gas shadow prices are obtained by adjusting the mid-83 market prices according to the assumption of an 85 per cent gas/oil energy price parity at Toronto city gate. The shadow prices are assumed to remain constant in real terms throughout the investment horizon. The shadow prices corresponding to the high oil price case are obtained by adding a premium of 9¢/m^3 to the above values; the resulting shadow prices are also assumed to remain constant in real terms.

Table 28

Commercial Evaluation of Four Geothermal Energy Projects

1. Market Prices of Natural Gas Used in Evaluation (1981¢/m^3)

Province	Residential Sector	Commercial Sector	Industrial Sector
Manitoba	15	13	11
Saskatchewan	12	11	10
Alberta	12	10	7
British Columbia	14	12	10

2. Paybacks and ROEs

	Residential Townhouse Space & Water Heating		Commercial Space and Water Heating		Greenhouse Heating		Mine Ventilation Air Heating	
Province	Payback (years)	ROE[2] (%)	Payback (years)	ROE[2] (%)	Payback (years)	ROE[2] (%)	Payback (years)	ROE[2] (%)
Manitoba	-	-	8.1	20.6	2.6	49.8	4.0	36.7
Saskatchewan	-	-	18.7	2.0	9.4	17.7	10.0	16.4
Alberta	-	-	-	-	-	-	-	-
British Columbia	-	-	7.4	22.5	2.4	53.6	5.1	30.6

[1] The market prices of natural gas (mid-83 values) taken from EMR's Statistical Handbook, Update #81 (1983), and converted to 1981 $.

[2] The rates of return are given in nominal terms; a 6 per cent long-run annual inflation rate is assumed.

Table 29

Economic and Commercial Analysis of a Wind Energy Project

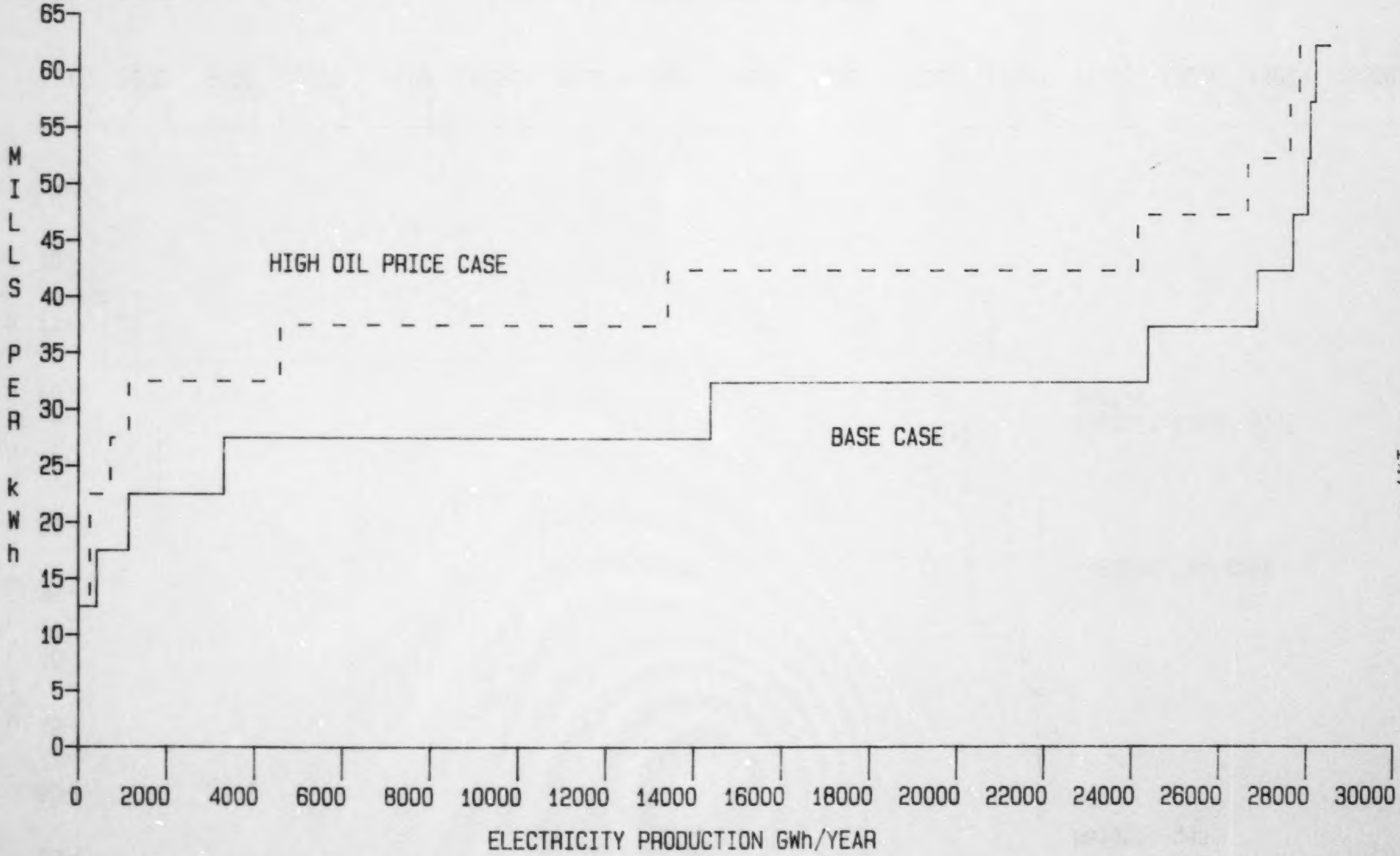
Cost/Price of Diesel Fuel (1981$/m^3)	Economic Analysis[1] Supply Price (1981$/m^3 of displaced diesel)	Commercial Analysis[2] Payback (years)	ROE[3] (%)
250	382	16	6
300	382	9	18
350	382	5	31
400	382	3	46

[1] Supply price calculated using a 10 per cent real discount rate.

[2] Diesel savings valued at the assumed market price as specified in column 1 (price held constant in real terms throughout the investment horizon).

[3] Rates of return expressed in nominal terms; a 6 per cent long-run annual rate of inflation is assumed.

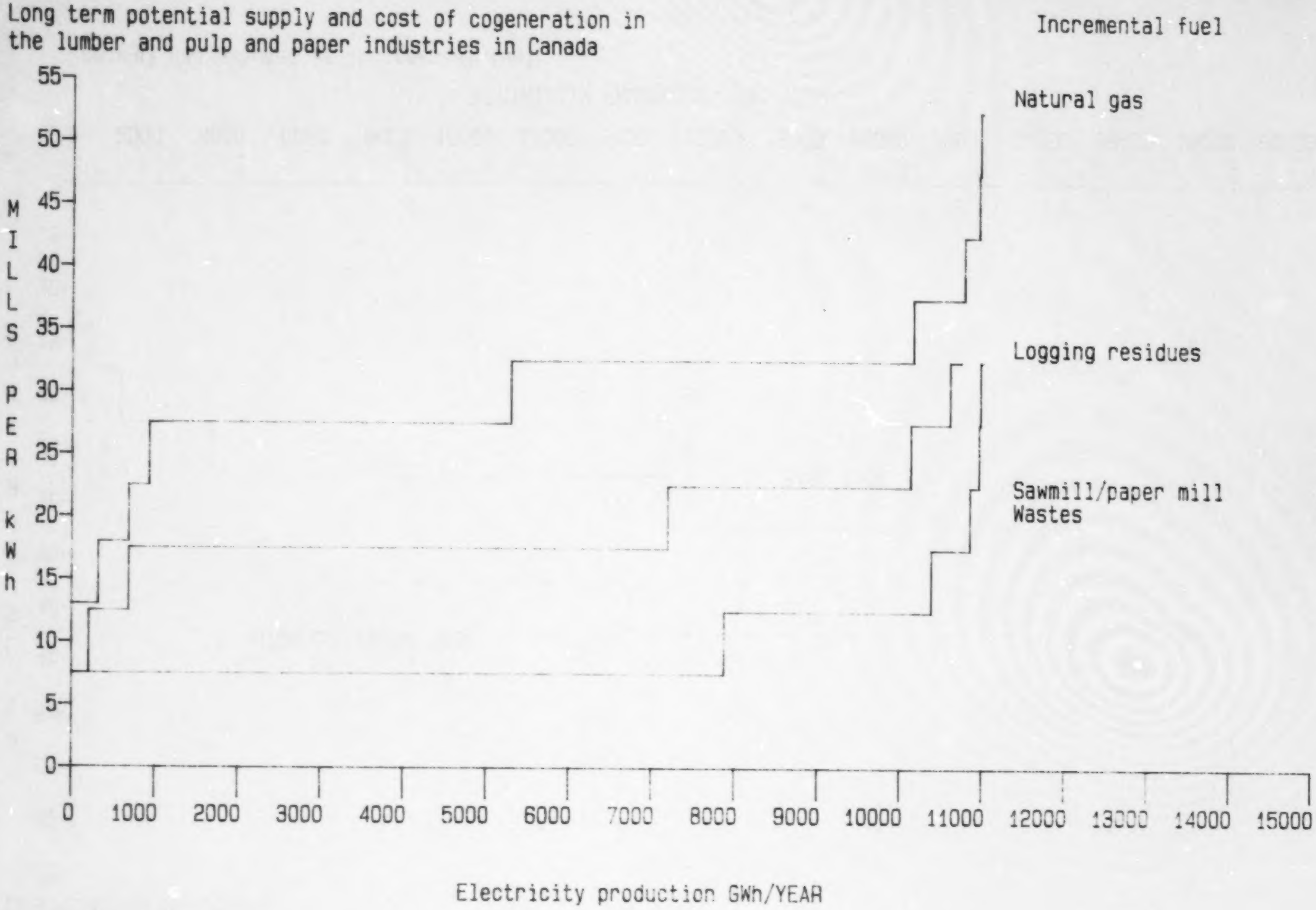
FIGURE 1
LONG TERM POTENTIAL SUPPLY AND COST OF COGENERATION IN CANADA



Natural gas assumed as incremental fuel

FIGURE 2

Long term potential supply and cost of cogeneration in the lumber and pulp and paper industries in Canada



Appendix 1

Prefixes, Abbreviations and Conversion Factors

Prefixes

kilo: 10^3
mega: 10^6
giga: 10^9
tera: 10^{12}
peta: 10^{15}

Abbreviations

GJ: Gigajoule
PJ: Petajoule

MW: Megawatt
kWh: Kilowatt-hour
GWh: Gigawatt-hour

m^3: Cubic meter
l: Litre
Odt: Oven-dry tonne

MSW: Municipal solid waste
EFW: Energy from waste
CNG: Compressed natural gas

Conversion Factors

Volume

1 cubic meter = 1,000 litres = 6.29 barrels

Energy

1 gigajoule = 0.95 million British Thermal Units (Btu)

= 25.9 litres, light fuel oil
= 24.0 litres, heavy fuel oil
= 25.6 litres, crude oil
= 26.9 cubic meters, natural gas
= 277.0 kilowatt-hours, electricity
= 0.05 oven-dry tonne, firewood

Appendix 2

Technical Parameters for Technology Evaluations

Table A1

Technical Parameters - Space Heating Options for Single Family Homes

Regional Space Heating Requirements for the New 1995 Home[1]

City	Energy Requirement GJ/year	Capacity Requirement kW
St-John's	61	6.0
Charlottetown	59	6.0
Halifax	53	6.0
Fredericton	60	6.0
Montreal	57	6.0
Ottawa	60	6.0
Toronto	52	6.0
Winnipeg	75	7.5
Regina	75	7.5
Edmonton	71	7.5
Vancouver	39	6.0

Space Heating Options - Cost and Performance Data[2]

Option	Capital Cost (1981$) 6 kW	Capital Cost (1981$) 7.5 kW	Operating and Maintenance Cost (1981$/year)	Seasonal Efficiency Factor[3]	Useful Life (years)
Conventional Oil Furnace	1,100	1,225	60	0.65	20
Conventional Gas Furnace	1,100	1,225	35	0.65	20
Electric Resistance System	1,100	1,225	0	1.00	20
Condensing Gas Furnace	1,980	2,175	35	0.95	20
Heat Pump	3,400[4]	3,400[4]	70	1.42 - 2.58[7]	20
Heat Pump (with air conditioning credit)	1,900	1,900	70	1.42 - 2.58[7]	20
Central Wood Furnace	3,750[5]	4,125[6]	85	0.60	20

[1] Author's estimates; energy requirements given in units of useful energy.

[2] Data collected from dispersed sources, including Ontario Ministry of Energy, "The Homeowner's Off-Oil Heating Conversion Decision - The Costs and Benefits", (1983 Edition), Toronto, 1983; and Cane, R.L.D., "Residential Space Heating with the Heat Pump", Building Research Note no. 125, National Research Council, Ottawa, 1978. Adjustments were made to reflect the lower energy and capacity requirements for the 1995 home.

[3] The seasonal efficiency equals the ratio of output, tertiary or useful energy to input or secondary energy. For example, a conventional oil furnace converts 65 per cent of its input energy to useful energy.

[4] Capital costs for the heat pump not adjusted for capacity; changes in the capacity and energy requirements are reflected in the seasonal efficiency.

[5] Includes the cost of a 6 kW backup plenum heater ($840).

[6] Includes the cost of a 7.5 kW backup plenum heater ($920).

[7] Seasonal efficiencies are 1.42 for Winnipeg, Regina and Edmonton, 1.64 for Ottawa, Fredericton and Montreal, 2.06 for Halifax, St-John's, Charlottetown and Toronto and 2.58 for Vancouver. Note that heat pump efficiencies are never less than 1.

Table A2

Technical Parameters - Cogeneration

Data on 202 projects include:[1]

- Province
- Industry SIC code
- Electricity consumption (GWh/year)
- Present cogeneration capacity (kW)
- Present cogeneration energy (GWh/year)
- Potential cogeneration capacity (kW)
- Potential cogeneration energy (GWh/year)
- Incremental capital cost (1981$)
- Incremental maintenance cost (1981$/year)
- Incremental fuel consumption (GJ/year)[2]

Project Life: 25 years

Incremental Fuel:

Natural gas: .037 gigajoule per cubic meter

Wood wastes: 17.5 gigajoules per oven-dry tonne[3]

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[1] Project data taken from Acres Shawinigan Ltd., Study of the Potential for Cogeneration in Canada, Industrial Steam Turbines, Volume I - Main Report, Energy, Mines and Resources Canada, Industry Series, Publication no. 1, December 1979; and Acres Consulting Services Ltd., An Economic Update of the Potential for Cogeneration in Canada, Industrial Steam Turbines, Energy, Mines and Resources Canada, Industry Series, Publication no. 1a, August 1982.

[2] Incremental fuel requirements expressed in terms of secondary units of oil or gas.

[3] Includes an adjustment for the lower efficiency of wood combustion.

Table A3

Technical Parameters - Waste Heat Recovery

Project No.	Application	Industry	Investment Cost (1981$ x 10^3)	Energy Savings (TJ/Year)[2]
1	Re-use of Compressor Cooling Water	Meat and Poultry	1.2	5.1
2	Flue Gas Heat Recovery	Bakery Products	2.7	1.5
3	Flue Gas Heat Recovery	Dairy Products	25.8	5.2
4	Hot Water Recovery	Meat and Poultry	42.3	6.1
5	Feedwater Heating with Waste Heat	Pulp and Paper	96.6	58.2
6	Re-use of Mezzanine Air	Pulp and Paper	32.5	11.8
7	Air Duct Relocation	Pulp and Paper	131.3	47.5
8	Paper Machine Hood System	Pulp and Paper	102.3	26.2
9	Flue Gas Waste Heat Recovery	Pulp and Paper	111.6	21.7
10	Heat Exchanger	Pulp and Paper	258.3	158.3
11	Boiler Economiser	Glass Products	10.5	7.0
12	Heat Recovery	Abrasives	25.2	4.9
13	Compressor Heat Recovery	Industrial Chemicals	2.5	1.4
14	Intermediate Reboilers	Industrial Chemicals	238.6	137.2
15	Boiler Blowdown Heat Recovery	Industrial Chemicals	12.5	5.5
16	Heat Recovery from Industrial Wastes	Industrial Chemicals	29.7	209.9
17	Heat Recovery from Feedstock Preheating	Industrial Chemicals	609.3	98.3
18	Ventilation Air Heated with Compressor Cooling Water	Metal Mines	381.9	69.2
19	Recirculation of Grid Resistor Heat	Metal Mines	2.2	1.4
20	Ventilation Air Heated with Compressor Cooling Water	Metal Mines	110.1	4.7
21	Underground Air Return to Heat Shaft House	Metal Mines	20.9	0.6
22	Recirculation of Excess Building Heat	Metal Mines	11.0	36.9
23	Use of Stratified Warm Air to Preheat Makeup Air	Metal Mines	145.9	47.6
24	Recirculation of Stratified Warm Air	Metal Mines	24.2	2.6
25	Boiler Preheat with Compressor Cooling Water	Metal Mines	7.4	0.2
26	Recirculation of Process Heat Into Building	Metal Mines	467.2	33.5
27	Using Cupola Flue Gas Heat for Makeup Air Heating	Transportation Equipment	615.1	101.7
28	Use of Heat Recuperators to Preheat Combustion Air	Transportation Equipment	12.5	6.2
29	Heat Recovery Unit in Building Heater Duct	Transportation Equipment	14.8	3.8
30	Waste Heat Recovery to Preheat Oven Makeup Air	Transportation Equipment	57.7	12.6
31	Use of Furnace Waste Flue Heat to Preheat Ingots	Transportation Equipment	40.4	22.6
	Average		117.6	37.1

Incremental Maintenance Costs: Zero in all cases.

Project Life: 15 years.

Displaced Fuel: Heavy fuel oil or natural gas.

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[1] Project data taken from General Motors Corporation, "Industrial Energy Conservation - 101 Ideas at Work", Energy Management Section, General Motors Corporation, Detroit, 1977; Diener, S.G. and B. James, "A Comparison of the Costs of Energy Conservation and Energy Supply in Canada", (edited and condensed from a report prepared by Acres Consulting Services Limited), Energy, Mines and Resources Canada, May 1981; and James, R.B., "Saving Energy and Money Through Energy Use Management - The Mining and Metallurgy Experience", mimeo, presented at CIM Annual General Meeting, Quebec City, April 1982.

[2] Fuel savings expressed in terms of secondary units of oil or natural gas.

Table A4

Technical Parameters - Biomass Energy (Energy-From-Waste Plant)[1]

Plant Costs:

Fuel Mix	Capital Cost (1981$)	Maintenance Cost (1981$/year)
100% Municipal Solid Waste (MSW)	9,900,000	875,000
50% MSW / 50% Sawmill Waste	9,900,000	795,000
100% Sawmill Waste	8,400,000	510,000

Waste Combustion: 180 tonnes/day capacity, 90 percent utilization factor (valid for any fuel mix).

Steam/Energy Supply: 20,000 kilograms/hour of steam, or 485 Terajoules of heavy fuel oil or natural gas equivalent (valid for any fuel mix).

Project Life: 20 years.

Construction Time: 2 years.

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[1] Project data taken from Acres Consulting Services Limited, Energy from Waste in North Bay, a study prepared for the Ontario Ministry of Energy, the Ontario Ministry of the Environment and the Nordfibre Company, Toronto, 1979, and Diener, S.G. and C.C. Smith, "The Comparative Resource Costs of Energy from Waste", (mimeo), presentation to Third Annual IAEE Conference or International Energy Issues, University of Toronto, Toronto, 1981.

Table A5

Technical Parameters - Alternative Automotive Fuels[1]

Vehicle Characteristics

Vehicle	Annual Fuel Requirement (litres of gasoline equivalent)	Useful Life (years)
Private Automobile	1,940	8
Fleet Automobile	4,400	10

Fuel-Specific Data

Fuel	Units	Units per Litre of Gasoline Equivalent[2]	Incremental Vehicle Cost		Incremental Maintenance Cost (1981$/year)
			Private Automobile (1981$)	Fleet Automobile (1981$)	
Diesel	litres	0.65	1,800	2,250	0
Propane	litres	1.35	900	900	-50
Compressed Natural Gas	cubic meters	1.05	1,800	1,800	-50
Methanol	litres	1.70	300	400	0

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[1] Acres' estimates.

[2] Include adjustments for the comparative efficiency of the fuel engines.

Table A6

Technical Parameters - Small Hydro

Project	Installed Capacity (MW)	Energy Production (GWh/year)	Capital Costs (1981$/kW)	Operating and Maintenance (1981$/year)	Useful Life (years)
1	2.7	20.5	1,340	44,200	50
2	2.0	9.0	1,180	28,900	50
3	0.7	2.9	3,500	27,700	50

Source: Acres Consulting Services Limited, An Analysis of Constraints to Small Hydro Development in Ontario, prepared for the Ontario Ministry of Energy, Toronto, September 1982.

Table A7

Technical Parameters - Geothermal Energy

Project	Application	Natural Gas Savings (m^3/year)	Capital Cost (1981$)	Operating and Maintenance Cost (1981$/year)	Useful Life (years)
1	Residential Townhouse Space and Water Heating (550 units)	1,100,000[1]	2,955,000	150,000	20
2	Commercial Space and Water Heating (215,000 m^2 floor area)	3,360,000	3,350,000	150,000	20
3	Greenhouse Heating	3,325,000	2,185,000	150,000	20
4	Mine Ventilation Air Heating	3,200,000	1,900,000	150,000	20

[1] Adjusted downward from original study to reflect lower heat loss assumptions.

Source Acres Consulting Services Limited, A Study of Low-Temperature Geothermal Applications, prepared for the National Research Council of Canada, Vancouver, 1983.

Table A8

Technical Parameters - Wind Energy

Project Data

Capacity per Wind Turbine (kW)	500
Investment Cost per Wind Turbine (1981$)	800,000
Operating and Maintenance Cost per Wind Turbine (1981$/year)	27,000
Diesel Fuel Displacement per Wind Turbine (cubic meters/year)	317
Number of Wind Turbines	6
Useful Life	20

Source Pigeon René, "Projet d'un mini-parc d'éoliennes aux Iles-de-la-Madeleine - Analyse Technico-économique pour Hydro-Québec (Rapport préliminaire)", Conseil national de recherche du Canada, Ottawa, 1982.